Ontario Energy Board

Commission de l'Énergie de l'Ontario

VT INCEPIT FIDELIS SIC PERMANET
Ontario

EB-2005-0001/EB-2005-0437

IN THE MATTER OF AN APPLICATION BY

ENBRIDGE GAS DISTRIBUTION INC.

2006 RATES

DECISION WITH REASONS

February 9, 2006

Summary of the Decision with Reasons[1]
(EB-2005-0001/EB-2005-0437)

Application	Board Decision
• $458.8 million capital budget	• $300 million approved
• New transactional services revenue sharing mechanism	• Continue with current mechanism. Forecast revenues of $10.7 million and expenses of $0.8 million included in rates
• Increase risk management price volatility tolerance band from $35 to $75 • Include $930,000 in rate base for software development costs	• Approved • Place amount in deferral account
• Accept assessment of EnVision program	• Report inadequate; new evaluation required for next rates case
• Gas supply activities including storage and transportation	• Approved
• $119.4 million customer care costs	• $104.1 million approved
• 12 year customer information system contract	• Not approved
• Third party access to utility bill by energy service providers	• More comprehensive proposal for non-discriminatory bill sharing required; to be filed in next rates case or sharing to cease
• New corporate cost allocation methodology to allocate services from Enbridge's parent • $21.3 million in corporate costs	• Methodology accepted; refinements needed • $17.2 million approved
• $185.5 million other operating and maintenance costs	• $176.5 million approved
• 2005 Ontario Hearing Costs Variance Account • 2005 Late Payment Penalty Revision Deferral Account • 2005 Transactional Services Deferral Account	• Application for separate account required for decision appeal costs • Account and balance not approved • Account balance accepted
• 2006 Customer Communication Plan Deferral Account • 2006 Corporate Cost Allocation Methodology Deferral Account • Manufactured Gas Plant Variance Account	• Account not approved • Account approved • Account approved
• Timing and proposed changes to 300 series of rates	• Issue will be considered in the Natural Gas Electricity Interface Proceeding (EB-2005-0551)
• 2006 rate implementation	• New rates approved effective January 1, 2006 with implementation April 1, 2006

[1] This summary does not form part of the Decision nor does it itemize all findings and is not to be relied on for the purpose of applying or interpreting the Decision.

TABLE OF CONTENTS

1. INTRODUCTION 2

1.1 THE APPLICATION 2
1.2 THE SETTLEMENT PROPOSAL 2
1.3 PARTIAL DECISION WITH REASONS ISSUED ON DECEMBER 22, 2005 4
1.4 SUBMISSIONS AND EXHIBITS 5

2. CAPITAL BUDGET 6

2.1 BACKGROUND 6
2.2 BOARD FINDINGS 9

3. ENVISION PROJECT 14

3.1 BACKGROUND 14
3.2 BOARD FINDINGS 15

4. GAS COSTS, TRANSPORTATION, AND STORAGE 19

4.1 BACKGROUND 19
4.2 BOARD FINDINGS 22

5. RISK MANAGEMENT 25

5.1 BACKGROUND 25
5.2 THE CUSTOMER THRESHOLD FOR GAS SUPPLY VOLATILITY STUDY 25
5.3 BOARD FINDINGS 27
5.4 THE TRANSITION OF THE PROGRAM TO DATABASE FORMAT 27
5.5 BOARD FINDINGS 27

6. TRANSACTIONAL SERVICES 32

6.1 BACKGROUND 32
6.2 BOARD FINDINGS 35

7. CUSTOMER SUPPORT COSTS (INCLUDING CUSTOMER CARE AND CUSTOMER INFORMATION SYSTEM) 39

7.1 BACKGROUND 39
7.2 BENCHMARKING 41
7.3 BOARD FINDINGS 41
7.4 COMPETITIVE MARKET COSTS OF SERVICES PROVIDED TO ENBRIDGE 44
7.5 BOARD FINDINGS 44
7.6 RATE OF RETURN FOR ECSI AND CWLP 47
7.7 BOARD FINDINGS 48
7.8 BOARD FINDINGS - CONCLUSIONS 51
7.9 INTEREST ON SECURITY DEPOSITS 52

8. CIS REPLACEMENT CONTRACT 54

8.1 BACKGROUND 54
8.2 IS A NEW CIS SYSTEM REQUIRED? 55
8.3 BOARD FINDINGS 55
8.4 HAS ENBRIDGE GONE ABOUT ACQUIRING A NEW CIS SYSTEM APPROPRIATELY? 55
8.5 BOARD FINDINGS 56
8.6 IS THE FEE STRUCTURE IN THE CONTRACT PRUDENT? 58
8.7 BOARD FINDINGS 58

8.8 ARE THE OTHER TERMS AND CONDITIONS OF THE CONTRACT APPROPRIATE? 60
8.9 BOARD FINDINGS 61
8.10 CONCLUSION ON NEW CIS CONTRACT 62

9. THIRD PARTY ACCESS TO CUSTOMER BILLS 63

9.1 BACKGROUND 63
9.2 SHOULD THIRD PARTY SERVICE PROVIDERS HAVE ACCESS TO THE BILL? 64
9.3 BOARD FINDINGS 64
9.4 WHEN SHOULD ACCESS BE PROVIDED? 66
9.5 BOARD FINDINGS 66

10. CORPORATE COST ALLOCATION 69

10.1 BACKGROUND 69
10.2 IS THE RCAM METHODOLOGY APPROPRIATE? 71
10.3 BOARD FINDINGS 72
10.4 HAS THE RCAM BEEN APPROPRIATELY APPLIED? 73
10.5 BOARD FINDINGS 74
10.6 DOES THE 2005 BOARD APPROVED AMOUNT FORM THE APPROPRIATE BASE FOR CONSIDERATION OF THE 2006 COST? 79
10.7 BOARD FINDINGS 79
10.8 DO THE RESULTING COSTS PASS THE 3-PRONG TEST? 79
10.9 BOARD FINDINGS 80
10.10 SHOULD THE BOARD BE CONCERNED THAT ACTUAL PAYMENTS TO EI WILL BE IN ACCORDANCE WITH CAM – NOT RCAM? 91
10.11 BOARD FINDINGS 91

11. OTHER O&M EXPENSES 92

11.1 BACKGROUND 92
11.2 WHAT IS THE APPROPRIATE LEVEL OF THE TOTAL OTHER O&M BUDGET? 93
11.3 BOARD FINDINGS 93
11.4 SHOULD ADJUSTMENTS OR SPECIFIC FINDINGS BE MADE ON THE INDIVIDUAL DEPARTMENTAL BUDGETS? 98
11.5 BOARD FINDINGS 99
11.6 SHOULD ENBRIDGE BE DIRECTED TO FILE SPECIFIC EVIDENCE WITH RESPECT TO THE NATURAL GAS FOR VEHICLES (NGV) PROGRAM? 100
11.7 BOARD FINDINGS 100

12. TIMING AND CHANGES TO THE 300 SERIES OF RATES 101

12.1 BACKGROUND 101
12.2 BOARD FINDINGS 102

13. GAS DISTRIBUTION ACCESS RULE 106

13.1 BACKGROUND 106
13.2 BOARD FINDINGS 108

14. DEFERRAL AND VARIANCE ACCOUNTS 109

14.1 HISTORICAL ACCOUNTS 109
14.2 2005 ONTARIO HEARING COSTS VARIANCE ACCOUNT 109
14.3 BOARD FINDINGS 110
14.4 2005 LATE PAYMENT PENALTY REVISION DEFERRAL ACCOUNT 111
14.5 BOARD FINDINGS 112
14.6 2005 TRANSACTIONAL SERVICE DEFERRAL ACCOUNT 112
14.7 BOARD FINDINGS 112
14.8 DEMAND SIDE MANAGEMENT ACCOUNTS 113
14.9 2006 ACCOUNTS 113
14.10 2006 CUSTOMER COMMUNICATION PLAN DEFERRAL ACCOUNT ("2006 CCPDA") 113
14.11 BOARD FINDINGS 114

14.12 2006 CORPORATE COST ALLOCATION METHODOLOGY DEFERRAL ACCOUNT 114
14.13 BOARD FINDINGS 114
14.14 2006 MANUFACTURED GAS PLANT VARIANCE ACCOUNT....115
14.15 BOARD FINDINGS 117
14.16 2006 ONTARIO HEARING COSTS VARIANCE ACCOUNT (2006 OHCVA)....117
14.17 BOARD FINDINGS 118
14.18 OTHER ACCOUNTS 118

15. RATE IMPLEMENTATION 119

16. COST AWARDS....121

<u>Appendices</u>

1 – Procedural Details Including Lists of Parties and Witnesses

2 – Settlement Proposal

3 – Partial Decision

EB-2005-0001
EB-2005-0437

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, C.15 (Schedule B);

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2006.

BEFORE: Pamela Nowina
Vice Chair and Presiding Member

Paul Sommerville
Member

Cynthia Chaplin
Member

DECISION WITH REASONS

February 9, 2006

1. INTRODUCTION

1.1 THE APPLICATION

1.1.1 Enbridge Gas Distribution Inc. ("Enbridge", the "Company", or the "Applicant") filed an application dated March 18, 2005 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998*; S.O. c.15, Schedule B, for an order or orders approving or fixing just and reasonable rates for the sale, distribution, transmission, and storage of gas for Enbridge's 2006 fiscal year commencing January 1, 2006 ("2006 Test Year" or "Test Year"). The Board assigned file number EB-2005-0001 to the Application.

1.1.2 Combined in this proceeding is an application from Enbridge, assigned file number EB-2005-0437, regarding the establishment of a deferral account to record Late Payment and Penalty System revision costs.

1.1.3 Appendix 1 contains details regarding some of the procedural aspects of the rates Application, including a list of witnesses and a list of parties.

1.2 THE SETTLEMENT PROPOSAL

1.2.1 On August 10, 2005, a Settlement Proposal was filed with the Board. During the course of the oral hearing, the parties to the Proposal filed two addenda, regarding issues 15.6 and 12.1, dated October 6, 2005 and October 27, 2005, respectively. A copy of the Settlement Proposal, including the addenda, is attached as Appendix 2.

1.2.2 Of the 67 issues on the Issues List, the Settlement Proposal includes the complete settlement of 24 issues and indicated that parties would not address these issues at the hearing. There was an issue for which there was a partial settlement, and the parties were unable to reach agreement on the remaining 42 issues.

1.2.3 Below is a list of issues which are presented in the Settlement Proposal as having been completely settled. The Board accepts the cost consequences of the Settlement Proposal and will not review these issues in this Decision.

Issue 1.1	Gas Volume Budget
Issue 1.2	Average Use Forecast for Rate Class 1
Issue 1.3	Average Use Forecast for Rate Class 6
Issue 1.4	Budget Degree Days – Proposal to change to the DeBever with Trend Forecasting Methodology
Issue 2.1	Appropriateness of the forecast of Other Service Revenue
Issue 3.3	Enbridge Gas Services (“EGS”) and Enbridge Operational Services (“EOS”) Services Agreements, as they relate to the provision of Transactional Services, to the extent not dealt with in EB-2005-0244
Issue 4.1	Recovery of amounts (estimated at $1.725 million) in the 2005 Class Action Suit Deferral Account (“2005 CASDA”)
Issue 4.2	Request to establish a 2006 CASDA
Issue 7.1	Estimates of the cost and mix of short-term and long-term debt for the 2006 Test Year
Issue 7.2	Determination of calendar ROE for the 2006 Test Year using the Board’s Guidelines
Issue 7.3	Appropriateness of including any standby credit fees in the Cost of Capital, and in the alternative, the amount thereof
Issue 12.1	EnTrac Master Service Agreements
Issue 14.1	Derivation of Income, Large Corporation, Capital and Municipal Property Tax amounts
Issue 15.6	Recovery of Shared Savings Mechanism (“SSM”) and Lost Revenue Adjustment Mechanism (LRAM) amounts for 2002 and 2003
Issue 16.3	Request to establish a 2006 Notional Utility Account Deferral Account
Issue 17.1	2006 Cost Allocation
Issue 17.2	Changes in revenue to cost ratios

Issue 18.1	Proposal for changes to the Rate Handbook
Issue 18.2	Direct Purchase Administration Charge and System Gas fees
Issue 18.4	2006 Revenue Deficiency allocation
Issue 18.5	Review of the rate impacts including Year 2 phase-in of Cost Allocation changes and material changes, if any, from RP-2003-0203 Settlement Proposal (Ref: clause 15.4)
Issue 19.1	Year 2 phase-in of cost allocation changes for upstream transportation, storage, peaking service and interruptible credits
Issue 19.2	Implementation of any other rate design changes

1.2.4 This Decision with Reasons will address the following issue groupings for which there was no settlement:

- 2006 Capital Budget
- EnVision Project
- Gas Costs, Transportation and Storage
- Transactional Services
- 2006 Operating and Maintenance ("O&M") Budget
- Rate Design for Rate 300 Series
- Gas Distribution Access Rule
- Deferral and Variance Accounts
- Rate Implementation

1.3 PARTIAL DECISION WITH REASONS ISSUED ON DECEMBER 22, 2005

1.3.1 The Board issued a Partial Decision with Reasons addressing the following issues:

- Proposal for a three year DSM (“ Demand Side Management”) plan (2006-2008), including O&M budgets and volume estimates
- Attribution of savings in jointly delivered programs
- Shared savings mechanism (“SSM”) incentive
- Market transformation programs and incentives
- Demand side management variance account (“DSMVA”) mechanism
- Disposition of the DSMVA for 2002 and 2003
- Revenue sharing for the Applicant’s delivery of electricity programs

1.3.2 The Partial Decision with Reasons is included as Appendix **3** to this Decision.

1.4 SUBMISSIONS AND EXHIBITS

1.4.1 Copies of the evidence, exhibits, arguments, and transcripts of the proceeding are available for review at the Board’s offices.

2. CAPITAL BUDGET

2.1 BACKGROUND

2.1.1 Enbridge proposed an increase in capital expenditures from the estimated $250.5 million in 2005 to $458.8 million for 2006. The Company claimed that it needs to address mounting demands on its gas distribution infrastructure being driven by requirements for pipeline integrity and remediation work, a need to support the provincial government in its effort to replace coal-fired electricity generation, new community attachments and new customers.

2.1.2 The major components of the capital budget are as follows:

- Customer related distribution plant expenditures of $172.8 million, representing an increase of $68.2 million over the 2005 estimate.
- System improvement and upgrade related expenditures of $235.3 million, representing an increase of $127.7 million over the 2005 estimate. This increase is mostly due to several major reinforcement projects and the accelerated bare steel and cast iron replacement program.
- General and other plant expenditures of $43.2 million, consisting of land, structures, and improvements ($5.5 million); office furniture, transportation heavy work tools and work equipment ($4.5 million); NGV compressor equipment ($0.1 million); and computers and communication equipment ($31.5 million).
- Capital expenditures for underground storage facilities of $6.9 million.

2.1.3 The requested capital budget would result in an increase in rate base of $174.1 million (net of accumulated depreciation and retirements) for the Test Year. The change in the forecast level of rate base is primarily a result of capital closeouts to rate base, capital expenditures and work in progress, changes in the value of the gas in storage inventory, and changes in working cash allowance requirement. Most of the rate base impact of the Company's proposed capital expenditures would occur in 2007, when most projects will be closed to rate base.

2.1.4 Enbridge described its approach to the budgeting process as a "bottom up" approach and explained that the capital budget is developed by assessing the needs of the business including customer growth, system reinforcement and infrastructure rehabilitation for safety and reliability needs.

2.1.5 Enbridge asserted that it has an ongoing legal obligation to address emerging legislative change in a timely manner. In this regard, the Company said that it has put into place certain policies and plans to respond to pipeline integrity legislation that has been introduced in Canada and the United States. As well, it is beginning to consider the appropriate response to distribution integrity related legislation that it expects will take effect in the near future.

2.1.6 Enbridge also requested Board approval of $31.5 million related to IT capital expenditures for computer, software and communications equipment. Enbridge submitted that its request for increased capital spending on IT is necessary to support EnVision (Work and Asset Management), EnTRAC (gas account tracking) and EnMar (meter management and large volume meter data processing) and to accommodate the integration of certain new customer care applications with the Company's existing applications. Enbridge maintained that the IT capital budget does not include any costs related to the implementation of new processes stemming from the Board's GDAR proceeding; nor does it include any expenditure for Strategic Information Management ("SIM") projects such as CIS.

2.1.7 Enbridge proposed an increase of $68.2 million in customer-related distribution plant expenditures. $36.3 million of this increase is earmarked as a placeholder for two potential power generation projects to be authorized by the Ontario government, pursuant to certain RFPs. Enbridge submitted that the provincial government's commitment to pursue new gas-fired electricity generation through the RFP process is evident in the fact that, at the time of filing, the government had already announced a 90MW plant for the Greater Toronto Airport Authority, and two 280MW plants for Mississauga. (One of these two 280MW plants has subsequently been withdrawn.) Enbridge reported that the government has recently indicated that it will be proceeding with another round of RFPs that will include a 1,000MW plant for "GTA West" and a 600MW plant for the downtown Toronto area. Enbridge submitted that Board approval of the requested amount would send a positive message that the natural gas industry is committed and ready to help address Ontario's electricity supply shortfall through the creation of appropriate infrastructure to serve such plants.

2.1.8 The capital expenditure budget proposed by the Company for system improvements and upgrades in the Test Year is $235.4 million and is comprised primarily of Total Improvement Mains of $146.2 million, representing an increase of $92.9 million above the amount in 2005. This increase is primarily due to several major reinforcement projects ($54.0 million) and the Company's accelerated bare steel and cast iron mains replacement program ($43.4 million). Enbridge submitted that the increased reinforcement main activity is driven primarily by the need to ensure adequate volumes and pressures across its distribution system in the face of the cumulative effects of years of new residential growth and commercial developments.

2.1.9 A number of intervenors argued that the proposed capital budget should not be approved and that a considerably lower budget should be approved. Intervenors cited a number of reasons for the Board to reduce the Company's capital budget proposal including:

- failure to provide evidence that adequately justifies major capital initiatives and individual programs;
- weaknesses in Enbridge's arguments linking increased capital requirements to any changed circumstances or new issues around safety, and
- new facts arising during the course of the rate proceeding that support lower capital requirements.

2.1.10 The intervenors proposed 2006 capital budgets ranging from $250 million to $300 million. In general, the intervenors argued that the Company should be able to manage within these levels, as these amounts are close to the Company's historic capital budget levels.

2.2 BOARD FINDINGS

2.2.1 It is not the Board's role in a rates case to micro-manage Enbridge's capital spending plans for any given year. Generally, Enbridge must determine for itself what level of spending is appropriate for a relevant period. This process within the Company must involve a thoughtful and programmatic assessment and prioritization of projects that have ripened to the extent that there is confidence that they can and should be accomplished within the period. This is particularly so in an environment that has seen significant increases in energy prices and where the Company is seeking a very substantial increase in overall capital spending. It may be that the Company will have to make choices about which projects are most critical, and which may have to await completion until future periods.

2.2.2 The Board's role is to ensure that the Enbridge's total spending program is balanced in that it is not so low as to threaten the orderly maintenance and development of the system, nor so high as to place undue upward pressure on rates, either in the test year or some future period. In fulfilling this role the Board attempts to place the capital spending plans within historical norms, which can be presumed to have found that appropriate balance. If spending well in excess of historic norms is proposed, the Board must assess whether the increase is justified through the presentation of evidence regarding the Company's analysis, prioritization, and judgement respecting budget components.

2.2.3 In the instant case, Enbridge has proposed an unprecedented increase in capital spending. The applied for amount represents an increase of over 80% of not only the previous year's budgeted amount, but also the average of the last five years. While the rate impact of this proposal in the Test Year may be modest, the implication of the budget for subsequent periods is significant. Over $400 million would be added to rate base for the 2007 rate year, which will result in a rate base impact of approximately 11% in that year.

2.2.4 In such a case the Board must examine Enbridge's proposal carefully to determine if such an unprecedented increase is balanced and justifiable or if the budget should be adjusted to enable the Company to make choices between programs of varying priority and at different stages of development.

2.2.5 To support the magnitude of the increase, Enbridge advanced the proposition that a number of extraordinary circumstances had come together at this time to create the need for this extraordinary capital spending budget. These circumstances are:

- extraordinary system expansion requirements;
- a pressing safety and reliability issue occasioned by cast iron and bare steel mains in Toronto; and,
- the advent of gas-fired merchant generation in its franchise area.

2.2.6 The Board is not convinced that Enbridge has proven that its environment has changed so markedly as to justify the proposed level of capital spending.

2.2.7 Looking first at the issue of expansion within Enbridge's system, the Board notes that the number of customer additions in 2006 is roughly the same as that for other years in the recent past. Enbridge suggested that there is not a linear relationship between customer additions in a given year and the capital expenditures necessary to accommodate them and that there is a point where the Company "catches up" for past years. This assertion by the Company is not supported by any direct evidence.

2.2.8 The Board notes that the rate of customer additions has been remarkably stable over the last number of years and considers that the capital budgets in each of those prior years should be presumed to, in aggregate, approximately accommodate the additions. In the Board's view, more compelling evidence is required before it can accept Enbridge's claim that this is an extraordinary year from a customer additions point of view and that such an unusually high level of capital spending is needed to accommodate them.

2.2.9 The acceleration of the bare steel and cast iron mains replacement program from 8 years to 3 years accounts for a significant portion of the increase in the capital budget for 2006. It is clear from the evidence that senior management intervened to accelerate the program and to increase the budget accordingly as a result of a change in its tolerance for the risks associated with managing this aging mains stock. The responsible engineering personnel had recommended a reduction in the spending amount for 2006. The technical challenges presented by the bare steel and cast iron mains did not change, nor did prevailing engineering practice. The existing program, which provides for a replacement of the bare steel and cast iron mains over an 8 year period, had been established by the Company's engineering staff and repeatedly presented and represented as being adequate to the risks associated with the mains. Nothing has intervened to change the adequacy of the 8 year replacement program, except senior management's risk tolerance.

2.2.10 Enbridge attempted to suggest that imminent changes in technical standards governing bare steel and cast iron pipe management would require an accelerated replacement program. In fact, Enbridge was unable to document or support this suggestion. No such change in the regulatory environment appears to be imminent.

2.2.11 Enbridge also suggested that an acceleration of the replacement program was justified because the anticipated decrease in the number of system leaks had not materialized. It looked to a study conducted by the American Gas Foundation to support this view. In fact, the AGF Study does not support or mandate the much more aggressive approach adopted by Enbridge for the purposes of this budget.

2.2.12 Similarly, Enbridge was unable to document any specific concerns on the part of the primary regulator of pipeline integrity in Ontario, the Technical Safety Standards Authority, with its 8 year replacement program. The Board also notes that Enbridge has not taken any steps to alert other public authorities, or its insurer, respecting a concern that the bare steel and cast iron mains now represent a previously underestimated danger to public safety.

2.2.13 What is clear from the evidence is that the acceleration of the bare steel and cast iron mains replacement program is the result of a change in senior management's risk tolerance, and not with any demonstrable change in the technical challenges presented by that pipeline stock. While it is laudable that the Company's senior management is focused on this program and determined to manage it aggressively, such a change in attitude without a change in the actual risk cannot justify an increase in the capital spending budget of the magnitude sought by the Company. Enbridge may choose, and perhaps, given Mr. Schultz' testimony, has already chosen, to afford the replacement program a priority beyond that which its own engineering forces identified, but it must do so within a budget that has not been unduly inflated to account for changes in mere risk tolerance.

2.2.14 Finally, Enbridge suggested that the prospect of new gas-fired electricity generation plants within its franchise territory justifies some extraordinary and significant increases in its capital spending budget. The increases are related to the construction of the infrastructure necessary to supply such plants with gas. This budget item references the prospect of gas-fired electricity generation and provides a "placeholder" for two potential generation plants in the Enbridge franchise area in 2006.

2.2.15 It is no secret that Ontario has identified a need for increased electricity generation. The Company has not provided any detail respecting imminent projects, and it would generally be considered unreasonable to insert placeholders in the budget without more substance. However, the Board, being mindful of the provincial imperative of developing more generation, is prepared to acknowledge that some provision should be made for as yet unspecified generation projects.

2.2.16 In conclusion, Enbridge has not demonstrated that circumstances exist which justify the extraordinary increase sought in the total capital budget. The Board does consider, however, that a case has been made for some increase in the budget over historical norms. While the Board is not convinced that the customer additions justify the extent of increase sought, it is prudent to make provision for some additional spending to ensure that system requirements are appropriately maintained. Similarly, while Enbridge has failed to support its claim for a radical acceleration of the bare steel and cast iron mains replacement program and the sharp increase in spending associated with it, some additional funds may be needed to adjust to developments in this area. The same kind of provision is appropriate for the development of infrastructure to support gas-fired generation projects and other system reinforcement.

2.2.17 Accordingly, the Board will approve a capital budget which is equivalent to the average for the five years 2001 to 2005 with an additional amount of $50 million to provide for the contingencies suggested by Enbridge in its evidence and general inflationary pressures. The total approved capital budget will therefore be $300 million.

2.2.18 In approving this budget amount, the Board leaves it to Enbridge's management to determine which projects it will pursue in the Test Year and at what pace it will pursue them. If the Company decides to accelerate the bare steel and cast iron mains replacement program, the Board would anticipate that claims for subsequent years would be reduced commensurately.

3. ENVISION PROJECT

3.1 BACKGROUND

3.1.1 The EnVision project involves a broad revision in a number of areas of Enbridge's operations and includes changes in business processes and human performance measures. The total cost of this project is approximately $123 million. The project is organized into two phases. The first phase, Work and Asset Management Solution, replaced 33 legacy systems and went live in October 2004. The second phase is the Field Force Transformation phase.

3.1.2 The EnVision project was first presented by Enbridge in the 2005 rates proceeding. In the 2005 Settlement Proposal, which was accepted and approved by the Board, the prudence of the EnVision program was agreed, and the 2005 costs were approved, subject to four commitments made by the Company. Three of those commitments were resolved prior to the filing of this Application. In this proceeding Enbridge is seeking the Board's acknowledgement that the fourth and final condition arising from the 2005 Settlement Proposal has been met.

3.1.3 The outstanding commitment from the 2005 Settlement Proposal required that the:

> …Company retain an independent consultant to assess the overall project costs to determine whether the fee levels and fee structure with Accenture are appropriate relative to the services and value being provided. In the context of this review the consultant will benchmark the services and costs described in the Services Agreement between Enbridge Gas Distribution Inc. and Accenture Inc. against the market.

3.1.4 Enbridge's approach to the fulfillment of its commitment was to hire HLB Consulting Inc. to perform an evaluation of the Accenture arrangement. The intervenors submitted that the HLB review fails to meet the Company's undertaking in two ways: HLB is not independent, and the review does not constitute a benchmarking of the costs associated with the Accenture arrangement.

3.1.5 Enbridge conceded that the assessment conducted by HLB is not a cost benchmarking analysis but asserted that the 2005 Settlement Proposal did not require cost benchmarking, but rather a broader and more comprehensive review of the overall value of the program to the Company. The witness from HLB also asserted that the complexity of the program did not lend itself to a narrow cost benchmarking analysis, and that a wider value-based perspective was needed.

3.1.6 Mr. Stephens, who testified on behalf of the Council, IGUA and VECC, insisted, in direct contradiction to the HLB evidence, that a cost based benchmarking analysis could and should be performed on the Accenture arrangement. His evidence provided some comparisons of the Accenture costs with what in his view were analogous arrangements in other jurisdictions.

3.2 BOARD FINDINGS

3.2.1 The Board's analysis of this issue must begin with a consideration of what was intended and provided for in the 2005 Settlement Proposal respecting the Accenture review. In this connection it is important to consider the extent to which the Accenture program had been subjected to objective cost comparison through competition, tendering or any other form of benchmarking. Confidence in these costs varies directly with such comparisons.

3.2.2 The Accenture program has never been subject to any programmatic comparison. The original RFP process in 2002 was unusual: it was a very broad project description and it had an 11 day turn-round. It is clear from Enbridge's evidence that each of the responding potential service providers had a different idea as to what was being solicited by the Company. The Accenture bid was the only bid to introduce the field force aspects of the ultimate proposal. Its inclusion led the Company to consider a fundamentally different project than had been under consideration up to that time. Enbridge entered into negotiations with Accenture respecting the design and redesign of the project, prior to entering into the Accenture contract in the spring of 2003.

3.2.3 In other parts of this Decision the Board has expressed its concern respecting Enbridge's tendency to grant significant business without providing the open marketplace a reasonable opportunity to bid. This is a very serious deficiency in the Company's practices in operating a regulated utility, and it must amend this tendency in future arrangements.

3.2.4 Enbridge felt that the costs of the non-field force elements of the program were within its expectations when comparing some elements of the project with its own cost projections, but that is really as far as its attempts to assess these costs went. The EnVision project, as it evolved, has never been subject to market comparison. It is hardly surprising that intervenors representing ratepayers have concerns about the appropriateness of the costs of the project which carries an ultimate price-tag of over $120 million.

3.2.5 Intervenor concerns found expression in the evidence they filed in the 2005 rates proceeding. That evidence was focused on the costs of the Accenture arrangement, and offered some preliminary comparative data. It is also not surprising that the Company considered the arrangement to be good value; surely Enbridge would not have entered into the Accenture contract if it felt otherwise. But as the parties entered the settlement discussion in 2005 it must have been clear that the ratepayer concern was cost, not value. The Settlement Proposal must be read with this in mind.

3.2.6 Excerpts from the Settlement Proposal speak directly to the ratepayer focus on cost, not value. In cross-exanimation, Mr. Stephens was very clear in his recollection that, at the time the 2005 Settlement Proposal was made the intervenors were not interested in a value assessment, but were committed to procuring a cost assessment. They believed that that was what the Settlement Proposal called for.

3.2.7 The perception that HLB had of the task before it is also revealing. In its response to the RFP for the benchmarking assessment it observed that "Enbridge's objective in the case at hand is to secure best value, not lowest price…." Enbridge appropriately involved the intervenors in the development of the RFP for the assessment mandated by the 2005 Settlement Proposal. Once the terms of the RFP were finalized, however, intervenor engagement ended, and from that point forward Enbridge controlled the process. This observation suggests that HLB was focused on Enbridge's interest in value, not the ratepayer interest in cost. It also suggests that HLB was not independent in its review.

In focusing on the Company's interest in a value assessment and taking direction exclusively from the Company, it did not perform an assessment of the costs related to the Accenture agreement.

3.2.8 Finally, it appears that HLB was not fully apprised of the extent to which the intervenors were seeking a cost review. While the 2005 Settlement Proposal required that the resulting assessment "meet the expectations of the intervenors," HLB had no contact and received no direction of any kind from the intervenors, nor does it appear that HLB was aware that the intervenors had such an explicit concern with the costs associated with the Accenture agreement. It is again not surprising that its report assessed the value of the program and did not benchmark its costs.

3.2.9 For these reasons the Board finds that the 2005 Settlement Proposal provided for a cost benchmarking assessment to be performed by an independent and competent party. No such report has been procured. While obviously competent, HLB was not appropriately directed to provide the required cost assessment, and did not perform its work independently, that is with input from both the applicant and the intervenors.

3.2.10 In consultation with the affected intervenors, a new RFP shall be circulated to an appropriate roster of consulting firms, which may include HLB. The terms of the RFP will include a clear statement to the effect that the product of the work is to be a cost benchmarking analysis related to the Accenture contract. Intervenors shall be given an adequate opportunity to ensure that this requirement is met and that the final report reflects the requirement. Selection of the consultant shall be agreed upon by the Company and the intervenors wishing to participate. The costs of the study shall be at shareholders' expense, in recognition of the inadequacy of the HLB report for the purpose it was intended to fulfill, and the need to undertake the work a second time.

3.2.11 This report shall be deliverable so that its findings can be taken into account in the 2007 rates case. In the event that the report indicates that the costs were materially in excess of market costs, the Board at that time will consider whether any adjustment is appropriate.

3.2.12 The Board will respond to the submission by some parties that the 2005 cost over-run of $1.95 million, due to project delays, ought to be disallowed, even though the matter had not been identified as unsettled in the Settlement Proposal. The Board recognizes that in the normal course of events, in large and technically complex projects such as EnVision, there will be some variation to plan. There is no evidence indicating that Enbridge is mismanaging the project or not responding to problems with appropriate mitigation measures. The Board does not see that the disallowance of $1.95 million is warranted under the circumstances.

4. GAS COSTS, TRANSPORTATION, AND STORAGE

4.1 BACKGROUND

4.1.1 The Company is seeking approval of the gas cost consequences of its gas supply activities including storage and transportation during the Test Year. The costs of these activities are forecast to total $1.97 billion. These costs are updated in each QRAM application. Any variances will be presented and addressed in either a QRAM application or as part of clearing the balances in the PGVA in the next rates case. The Company is not seeking pre-approval of any long term storage, transportation or supply contracts as part of this Application.

<u>Gas Storage</u>

4.1.2 The total cost of its storage and associated transportation for 2006 is forecast to be $92.5 million. Enbridge has underground storage at Tecumseh and its Crowland facility. It also has storage service entitlement with Union Gas Limited ("Union"). In RP-2003-0203 the Board denied Enbridge's application to replace the existing contract with Union with a new long term storage contract at market prices. The Union contract is currently priced using cost-based rates and expires on March 31, 2006. Enbridge has assumed that the costs relating to the existing Union Gas storage capacity will be maintained in the Test Year. Enbridge has not yet formalized any arrangement for replacement of the Union storage. The Company has stated it will seek Board approval to recover the costs of the services resulting from any new storage contract.

4.1.3 On December 29, 2005, the Board issued a Notice of Proceeding, file no. EB-2005-0551, regarding its upcoming review of the economic regulation of storage (the Natural Gas Electricity Interface Review). This Notice stated that the Board will convene a proceeding on its own motion to determine: (i) whether it should order new rates for the provision of natural gas, transmission, distribution and storage services to gas-fired power generators (and other eligible customers); and (ii) whether to refrain, in whole or in part, from exercising its power to regulate the rates charged for the storage of gas in Ontario by considering whether, as a question of fact, the storage of gas in Ontario is subject to competition sufficient to protect the public interest.

Gas Supply

4.1.4 Enbridge's total supply cost for the Test Year is forecast to be $1.44 billion. Enbridge expects to obtain its system gas supply during the Test Year as shown below:

Enbridge Test Year Gas Supply Sources

Contract Type	10^6 m^3	%
Western Canadian Supply	1,830.4	36.4
Ontario Production	1.5	0.0
Peaking	29.3	0.6
Chicago Supply	2,276.5	45.3
Delivered Supply	891.7	17.7

4.1.5 There has been a significant shift in Enbridge's supply pattern over the past 5 years. In 2001, Western Canadian Supply represented 78.5% and Chicago Supply 13.7%.

4.1.6 Enbridge estimated the commodity prices for these supplies using the simple average of forward quoted prices for the 12 months starting January 1, 2006, as reported by various media and other services over a period of 21 business days (November 12, 2004 to December 14, 2004) for a basket of pricing points and pricing indices that reflect its gas supply acquisition arrangements. Commodity costs are updated as part of Enbridge's QRAM applications.

Gas Transportation

4.1.7 Enbridge's forecast for the total cost of its transportation arrangements is $134 million. Enbridge has firm transportation and other service entitlements with a number of pipelines for system gas sourced in Western Canada and in the United States. The rates or tolls for these services are based on the rates in effect at October 1, 2004. Enbridge noted that TCPL's tolls for 2004 are interim tolls and are subject to change.

4.1.8 The MichCon contracts, the Link Pipeline contract and the ANR contract from Columbus to Corunna expire October 31, 2006, and will be replaced or renewed within the Test Year. For those contracts that have an expiry date within the Test Year Enbridge has assumed that they will be renewed at the existing parameters, demand levels and tolls. The Company stated that it has not made any decisions as to whether it will replace or renew these arrangements but that it intends to undertake a cost benefit analysis before making decisions to renew or replace expiring contracts. Enbridge submitted that while the total landed cost of the supply over the term of the contract is the primary deciding factor, there are other relevant considerations, such as ensuring that there is an appropriate diversity of supply sources.

4.1.9 Enbridge noted that any changes in transportation costs that arise over the course of the year will be captured in the PGVA and subsequently cleared after the appropriate regulatory scrutiny of these costs. It does not seek any Board approval for the terms and conditions of its transportation arrangements, including those that will expire during the Test Year, and which may be subject to renewal or replacement.

4.1.10 In the course of cross-examination, the intervenor TransCanada PipeLines ("TCPL") attempted to illustrate that, based on the tolls in effect at the present time, its transportation rates are lower than those being charged on the ANR-MichCon-Link supply path. As noted above, the Company now procures a substantial portion of its supply through the ANR-MichCon-Link. TCPL calculated that using its supply path in place of the ANR-MichCon-Link arrangement could reduce costs by $4 million per year. TCPL also suggested to the Enbridge witnessses that the contractual terms governing

TCPL supply were more favourable than those offered by the ANR-MichCon-Link routing. TCPL argued that the Board should mandate the use of its supply where economies are shown to exist.

4.1.11 The issue of the Board's role in pre-approving long-term arrangements was raised during the proceeding. In its Natural Gas Forum Report the Board stated that it "is not in favour of new long-term utility contracts at this time". It went on to state "the Board believes that there is a role for utilities in long-term upstream transportation contracting subject to a prudence review" and that "the Board will offer utilities the opportunity to apply for pre-approval of long-term supply and/or transportation contracts. The Board will consult on the development of guidelines …" Some parties encouraged the Board to conduct some form of review for contracts that come up for renewal in the Test Year. Enbridge indicated its support for the opportunity to get pre-approval of long-term contracts. Such approval would likely reduce the risk of a subsequent disallowance of cost recovery. However, Enbridge questioned the advisability and appropriateness of engaging the Board in the pre-approval of the number of contracts that could come up for renewal in any given year.

4.2 BOARD FINDINGS

4.2.1 Enbridge's proposal is approved for the Test Year.

4.2.2 The number of contracts requiring renewal and the amount of gas subject to those contracts is minimal in light of the Company's overall requirement. The Board does not see its role to lie in the micro-management of the supply portfolio. It is, however, always incumbent upon the Company to make arrangements for supply which are prudent. If, in the next rate case, it is established that Enbridge has entered into supply arrangements which are not prudent, the costs associated with those arrangements may not be recoverable. Any prudence review would be conducted on the basis of information that was, or should reasonably have been, available to Enbridge at the time of its decision.

4.2.3 Price is certainly a key consideration in the selection of a supply alternative. Where the Company chooses supply that is not the cheapest available, it must have a convincing case that the chosen option carries with it a counterbalancing advantage for ratepayers which justifies the increased cost. In this case, Enbridge has suggested that diversity of supply may have value for ratepayers. This proposition will have to be supported with evidence demonstrating such value, where it is used to justify a premium cost for supply.

4.2.4 Where supply arrangements are made with or involving affiliated or related entities, Enbridge will have to demonstrate that the chosen arrangements are the most prudent. In such circumstances the Company would do well to make all aspects of such arrangements open and transparent to the Board and interested parties and to ensure that its contracting parties are fully prepared and able to disclose all aspects of the arrangements in a regulatory process. Too much time and resources are expended in prying details of such transactions from reluctant contracting parties. In the Board's view, Enbridge has an obligation to make its supply and transportation arrangements, in all their complexity, available for scrutiny by ratepayers and the Board.

4.2.5 There was considerable discussion in this case respecting the Board's role in the pre-approval of supply arrangements. As indicated earlier, the Board has committed to consult interested parties on the pre-approval of "long-term transportation and/or supply contracts" as part of the NGF. The Board issued a letter on September 14, 2005 revising the timelines for the consultation process for contract pre-approval, and this process is expected to start in the first quarter of 2007. The Board also indicated that it would entertain applications for pre-approval if and when they are filed.

4.2.6 One of the issues will be establishing the definition of contracts which would be subject to pre-approval. The Company witnesses in this proceeding seemed to regard this issue fairly narrowly. They implied that only long term supply contracts which are entered into to support the construction of new pipeline infrastructure would fall under the scope of the Board's pre-approval. On the other hand, certain intervenors suggested that the scope for pre-approval should include a much broader scope, such as short term contracts which are subject to repeated renewals. The Board will not attempt to anticipate the outcome of the NGF consultation on this subject or of an application for contract pre-approval, and it is not necessary to do so for the purposes of this Decision.

5. RISK MANAGEMENT

5.1 BACKGROUND

5.1.1 The role of and nature of the risk management program has been the subject of continuous revision and evolution. The very purpose of the program, as well as the rules governing its execution, has changed markedly over the last few years. As part of this process, Enbridge was required to procure expert advice and to present the resulting report to the Board. Enbridge retained RiskAdvisory, a recognized expert in the design and implementation of risk management activities at utilities. The resulting RiskAdvisory report was filed in the RP-2003-0203 proceeding and contained 16 recommendations. In that proceeding, Enbridge addressed seven of the RiskAdvisory recommendations and advanced three of its own proposals for changes in the program. In the current proceeding, Enbridge brought forward its plans for implementing the remaining nine recommendations.

5.1.2 Specifically, Enbridge is seeking Board approval for two aspects of the risk management program:

- an increase in the price volatility tolerance band from the current $35 level to $75 level, based on the findings of the Customer Threshold for Gas Supply Volatility Study; and

- the closing to rate base of approximately $930,000 related to the transition of the program from a spreadsheet format to a database format.

5.2 THE CUSTOMER THRESHOLD FOR GAS SUPPLY VOLATILITY STUDY

5.2.1 In RP-2003-0203, Enbridge indicated the need to survey its customers in order to better understand their sensitivity to price volatility and to use these findings to update the $35 price volatility tolerance level identified in the surveys undertaken in 1994 and 1995.

Enbridge commissioned Ipsos-Reid to conduct the survey and identified the following specific objectives for the research:

- Assess customers' level of knowledge, understanding and expectations about gas pricing and the Company's role in the process.
- Determine customers' expectations about gas prices and their sensitivity to price volatility.
- Understand customers' preferences for risk management strategies in general and under different market conditions.
- Determine customers' preferences for the frequency of bill adjustments.

5.2.2 According to Enbridge, the results of the survey indicated that customers are tolerant of fluctuations of less than $75 in the commodity portion of their annual bill. A significant majority of customers indicated a preference that price volatility risk be managed. Customers were also asked about their preference for risk management strategies. Enbridge reported that while under a variety of scenarios a vast majority of customers indicated a desire for some form of hedging activity, they were generally evenly divided in choosing among the alternatives.

5.2.3 Given the survey results, Enbridge requested Board approval for an increase in the price volatility tolerance band from the current $35 to $75. It further stated that there would be no change in the hedging methodology employed, which was previously approved in RP-2003-0203. The proposed change in the volatility tolerance band has the effect of materially reducing the amount of hedging activity authorized and undertaken by the program.

5.2.4 While some intervenors expressed concern with the survey design, they supported increasing the tolerance level on the grounds that it may lessen the administrative burden of the program. It was also suggested that the sharp increase in commodity prices since the implementation of the $35 level justified a change. Indeed, some intervenors argued that the level of the tolerance band should be higher than that sought by the Company, given the higher prevailing commodity price level.

5.3 BOARD FINDINGS

5.3.1 The Board notes that there was no opposition to the raising of the threshold per se, and approves the changes applied for with respect to the adoption of the $75 action level. The issues raised by those intervenors which oppose the program in whole are addressed in the next section.

5.4 THE TRANSITION OF THE PROGRAM TO DATABASE FORMAT

5.4.1 Enbridge submitted that since the risk management database will be placed in service by the end of 2005, it is appropriate to close all amounts spent on the project to rate base by the end of the year. Enbridge noted that the cost to convert the functionality of the model from a spreadsheet to a database format is estimated at $930,000.

5.4.2 Enbridge's proposal to include these costs in rate base led to the examination of the purpose and effectiveness of the overall risk management program and concerns with respect to duplication of functionality within the context of the Quarterly Rate Adjustment Mechanism ("QRAM"), the Purchase Gas Variance Account ("PGVA") and the equal billing program.

5.4.3 Some intervenors argued for the discontinuation of the risk management program and argued that it would be inappropriate to include the $930,000 in the 2006 opening balance for rate base. Enbridge argued that the issue was beyond the scope of this proceeding, insofar as the termination of the program did not appear on the Issues List, nor did any intervenor take the appropriate steps to include it on the Issues List.

5.5 BOARD FINDINGS

5.5.1 The Board has never previously focused its attention on the specific expenditures made to transition the program to the proposed database format. Enbridge made this transition without specific Board approval or direction. Its evidence that program administration had become unwieldy and unnecessarily complex was not challenged by those intervenors who opposed the Company's proposal. They directed their attention to the fundamental utility and advisability of the program as a whole.

5.5.2 Some intervenors strongly supported the risk management program, seeing it as a measure of protection, especially for low-income consumers, whose tolerance for price volatility was suggested to be less than that of other customer groups. They argued that many consumers, particularly low-income consumers, are vulnerable to steep price fluctuations, especially in an environment where there seems to be a generally upward tendency in commodity prices.

5.5.3 On the other hand, others are strongly opposed to the program, and regard the expansion of the actionable volatility level to $75 as tinkering with a program that should be eliminated.

5.5.4 Energy Probe, supported by CME, IGUA and the retail gas marketers, opposed the continuation of the risk management program. Energy Probe presented evidence by Mr. Adams, its Executive Director, which focused on two points:

- Given that the program is designed merely to smooth the impacts of market prices of the commodity, and not to lower them, it is of no real value to consumers. The "real" price will always emerge sooner or later, and consumers are not served by the illusion that the market price is actually being affected by the hedging activities of the utility.

- There is value in ensuring that consumers have direct experience of the actual price of the commodity that they consume. Any softening of that experience through hedging activities obscures the market price signal. Consumers are best served when they receive an accurate and un-hedged price signal from the market because they can vary consumption according to such signals.

5.5.5 This last concern motivated the retail gas marketers to oppose the program and any increased spending associated with it. In their view, the smoothing of price volatility sends inaccurate signals to the consumer, and improperly undermines the attraction of their fixed-price offerings in the marketplace. The dominant position of Enbridge which derives from its standard service supply monopoly is, in their view, exacerbated by the smoothing of commodity price fluctuations. They argued that the transparency of the price is an important element in their competitive environment. They contended that they are operating at a competitive disadvantage to the extent that the risk management program blurs that transparency.

5.5.6 An important part of the background to this issue is the existence of the Quarterly Price Adjustment Mechanism (“QRAM”). Some form of QRAM is applied to all privately held gas distribution utilities in Ontario, including Enbridge. While there are important differences in the respective methodologies, they share the effect of moderating and smoothing anticipated commodity price fluctuations. As part of the Natural Gas Forum, the Board expects to consider the standardization of QRAM methodology across all utilities.

5.5.7 As part of the QRAM process, the Board also provides for the maintenance of and disposal of the Purchased Gas Variance Account. This account captures the difference between the Company’s projected cost of system gas and the actual cost. Its clearance also has the effect of smoothing commodity price fluctuations, insofar as the clearance of the account is distant in time from market purchases.

5.5.8 Finally, the Board notes the availability of equal billing plans for most residential customers. Such plans also have inherent smoothing effects, given that customers pay an averaged monthly amount which is subject to a true-up at or near the year end.

5.5.9 All of which is to say that in its implementation of the QRAM, its approach to the PGVA and the existence of equal billing plans, the Board accepts the principle that some form of price smoothing is an appropriate consumer protection measure. It is also important to emphasize that no matter what smoothing techniques are employed, the most that can be hoped for is a reduction in volatility, not an overall reduction in the price of the commodity over time. Subject to possible generational anomalies, consumers, both large and small, will pay the full burden of the market price for the commodity, sooner or later.

5.5.10 The question that remains is the extent to which Enbridge's risk management program is redundant or represents a useful and cost effective tool to reduce consumer price volatility in a fair and reasonable way. The Company provided evidence which seemed to show that its hedging activity smoothed <u>its</u> experience of commodity price fluctuations. No evidence has been provided that demonstrates whether the hedging activity had a material effect on the volatility experienced by customers, given the effects of QRAM, the PGVA, and equal billing programs over the same period. If hedging activity has no material effect on the volatility experienced by customers, then it may be that the risk management program is not required.

5.5.11 Accordingly, the Board directs Enbridge to prepare for consideration in its next rates case evidence which demonstrates the extent to which the Company's hedging activities in 2003, 2004, and 2005 would have resulted in reductions in volatility for its customers, had it applied the proposed $75 action level.

5.5.12 Enbridge asserted that the continuation of the program is not an issue in this proceeding, and that the intervenors who argued for its elimination in this case are seeking an outcome that is simply beyond the Board's scope. This point of view was supported by several intervenors that support the program, if not the specific changes sought by the Company.

5.5.13 While it is unnecessary to decide this point for the purposes of this Decision, given the Board's disposition of the issue in this case, the Board considers it appropriate to address the underlying proposition. The Board considers that where convincing evidence is presented which leads to a compelling conclusion that a program does not provide value to ratepayers, it is always open to the Board to disallow any further spending on the program, whether or not the issue falls within the four corners of an issue on the Issues List. The Board would clearly have a duty to exercise this discretion only in the most compelling case and never without offering the Company an appropriate opportunity to rebut the evidence supporting the termination of the program. The overriding principle is that in a rates case the Board always retains jurisdiction to make whatever order is necessary to establish just and reasonable rates. Requiring ratepayers to pay for operations that have been demonstrated to be without value to ratepayers is unreasonable.

5.5.14 The Board notes that Energy Probe's evidence was subject to all of the normal procedures. The Company cannot assert that it had no notice of, or was unduly prejudiced by the Energy Probe evidence. If the Company intended to insist that the termination of the program was out of scope, it should have done so when first presented with the Energy Probe evidence urging that outcome.

5.5.15 The Board will not order the discontinuation of the program for the Test Year. The Board is, however, concerned about the fundamental appropriateness of the program, and accordingly has directed the Company to develop evidence respecting its effects, as detailed above. In the interim, pending the Board's consideration of that evidence in the next rates case, the sums expended to upgrade the Program to a database format will not be released to rate base. Instead, the relevant sum, thought to be approximately $930,000, shall be placed in a deferral account exclusive to this purpose. The deferral account will be disposed of according to the Board's finding in the next rates case.

6. TRANSACTIONAL SERVICES

6.1 BACKGROUND

6.1.1 The Transactional Services ("TS") function was established in 1997 to enable Enbridge to trade in storage and transportation capacity which is surplus to its requirements to serve its in-franchise customers. Revenue is generated through the sale of this surplus capacity to in-franchise and ex-franchise markets. Examples of TS services include peak storage, off-peak storage, loans, exchanges, load balancing and transportation assignments for terms of one year or less. In the roughly 2-year period 2003 to early 2005, the Company also created bundled transactional services, using the gas commodity to enhance the standard service offerings. However, the Board ordered an end to this practice in its RP-2003-0203 Decision, citing a longstanding concern about the effect that this bundled trading could have on the competitive natural gas marketplace. In that Decision, the Board also ordered the Company to develop and implement a new methodology to ensure that surplus capacity was made available on a non-discriminatory basis.

6.1.2 There are two unsettled issues related to TS:

- the gross margin forecast
- the proposed new revenue sharing mechanism

6.1.3 A TS gross margin forecast and revenue sharing mechanism have been in place since TS was first established. This revenue sharing mechanism is designed to provide a return to ratepayers, in recognition of the fact that the costs of the assets have been included in rates. The Board has also always provided for a return to the shareholder as form of incentive, to encourage Enbridge to pursue the sale of the surplus assets vigorously.

6.1.4 The Board-approved sharing mechanism and forecast TS gross margin have remained basically unchanged for the past three years. For fiscal 2003, 2004 and 2005, Enbridge ratepayers were guaranteed $8 million in TS gross margin. The "guarantee" came about because the $8 million was credited to the Company's revenue requirement, as part of the prospective test year rate-setting process. The sharing mechanism further specified that the next $2.7 million in TS gross margin would be credited to the shareholder's account. Any amounts above $10.7 million were to be shared 75% to the account of the ratepayer and 25% to the account of the shareholder. The Transactional Services Deferral Account ("TSDA") captured the variance between the actual gross margin and the forecast amount. Amounts in the TSDA are disposed of and split according the 75:25 ratio, after the fiscal period ends. An exception to this rule would arise if the TSDA amount were negative, in which case the negative amount would be solely the responsibility of the shareholder.

6.1.5 Enbridge proposed a number of significant changes to the existing sharing mechanism for 2006. First, Enbridge proposed that the gross margin forecast be eliminated. This effectively means that there would be no ratepayer "guarantee" included in the rates. Second, the Company proposed that all of the amounts recorded in the TSDA would be shared equally between the ratepayer and the shareholder, instead of the current practice which affords ratepayers 75% of funds captured in the TSDA. Enbridge also proposed that the first $800,000 in gross margin be used to recover the incremental O&M costs associated with providing TS. This is in contrast to the current mechanism whereby the O&M costs of operating the TS function are borne by the shareholder.

6.1.6 The reasons cited by Enbridge for the proposed changes included the following:

- changes in the gas marketplace and the regulatory environment, especially the new TS methodology, which was approved by the Board in proceeding EB-2005-0244 in July 2005, and which Enbridge asserted introduces serious uncertainties;

- the need for new gas-fired power generation and its potential impact on load balancing services which may have the effect of materially curtailing the amount of surplus assets available for trade;

- weather uncertainty;

- the trend toward toll unbundling and its impact on which assets are held and used;

- possible TCPL service changes and the related potential impact on storage injections which have made accurate forecasting difficult;

- the risk/reward sharing of the current methodology which is asymmetrical and needs to be brought into balance in order to provide an appropriate incentive for Enbridge;

- the unfair asymmetrical risk faced by the Company if it fails to realize the guaranteed amount of revenue from TS sales; and

- other sharing mechanisms employed by the Board, for example, the 2004 earnings sharing which was struck on a 50:50 basis, which provide a sufficient incentive for the Company.

6.1.7 A number of intervenors made wide-ranging submissions about how the Board should proceed with Enbridge's TS proposals. Even though intervenors were united in their arguments that the Board should not accept the Company's TS proposals because they provide excessive returns to the shareholder, the intervenors' solutions were diverse. Most intervenors countered the Company's position that it is not possible to forecast the results of the TS business. Some accepted the Company's argument that the TS business faces uncertainty and revenue forecasts should be lower than recent practice; others said that the new TS methodology may actually increase gross margins.

6.1.8 There was significant variation among the intervenors' proposals for a solution to the TS revenue sharing question. The amounts suggested for inclusion in rates ranged from $6.5 million to $14 million. The proposals for the sharing of deferred amounts were even more disparate.

6.1.9 Some intervenors agreed with Enbridge that it should be able to recover its O&M expenses for running the TS business.

6.2 BOARD FINDINGS

6.2.1 In the Board's view, there are four questions that need to be answered:

1. Can a reasonable forecast be established and, if so, what is the appropriate amount?

2. Should ratepayers get a financial "guarantee" embedded in rates?

3. What sharing ratio provides an appropriate encouragement for Enbridge to optimize its TS activity, while providing a reasonable return to ratepayers?

4. Should TS O&M expenses be a ratepayer or shareholder responsibility or be shared?

6.2.2 The Board believes that these questions are linked. The resolution of all four questions should create an appropriate balance between Enbridge's obligation to optimize the use of the assets paid for by the ratepayer, and a reasonable inducement to encourage a vigorous approach to such optimization. The inducement should be no larger than is necessary to ensure that Enbridge dedicates sufficient resources to meet its obligation.

6.2.3 The first question is whether a reasonable forecast can be established for 2006 and if so, at what level. The Board does not question that forecasting for TS involves uncertainties. The Board accepts that the TS revenue forecast cannot be established with the same degree of confidence that can be attained in some other budget areas. However, a measure of uncertainty does not mean that a forecast cannot be developed, especially in light of eight years of actual experience in the activity. All businesses produce forecasts in the face of uncertainty. The Board does not accept that no forecast can be developed for TS.

6.2.4 In terms of the level of the forecast, the Board notes that in examining the historic numbers on TS, the pattern of TS gross margin results does, in fact, demonstrate some variability. Some of this variability was brought about by the introduction of bundled commodity transactions, a practice that, as noted above, has been terminated pursuant to a Board direction made in conjunction with its Decision in RP-2003-0203.

6.2.5 If the historic amounts are examined after excluding the gross margin amounts attributable to commodity transactions, the amounts would be as shown in the following table.

TS Gross Margin ($ millions)

2001	2002	2003	2004	2005
14.1	9.4	7.6	8.2	13.7

6.2.6 The amount provided for 2005 by Enbridge was an estimate as at the end of May 2005. On a “best efforts” basis, the Company asserted that its 2006 TS gross margin forecast would be between $5 million and $8 million.

6.2.7 The Board notes that the simple average of the numbers in the table is $10.6 million. With respect to Enbridge’s “best efforts” forecast for 2006, the fact that the 2005 mid-year forecast for the year is well in excess of that, and in view of historic results, the “best efforts” number appears to the Board to be low. The Board therefore views a 2006 forecast of TS gross margin of $10.7 million as a reasonable estimate. This amount has been used for the gross margin forecast the last few years, without undue advantage or prejudice to ratepayers or the shareholder.

6.2.8 Rather than being a negative influence, as suggested by Enbridge, it is the Board’s view that the new TS methodology, approved by the Board in 2005, is likely to increase market confidence, and support returns on the surplus assets. The new process, which is to be operational early in 2006, is characterized by increased transparency and enhanced access to the surplus assets for other market participants. This should have the effect of increasing the market value of the surplus assets.

6.2.9 As to the sharing mechanism, the Board supports now, as always, the existence of an appropriate inducement for the Company to ensure that it pursues its obligation to optimize realization on the surplus assets vigorously. The Board notes that the Company substantially out-performed the Board's gross margin targets for TS during 2003, 2004 and the portion of 2005 when it bundled commodity in the transactions. The Board recognizes that the Company's shareholder realized attractive profits during this period, even at the 25% level of sharing. Even in the absence of bundled commodity transactions, the Board views the activity as having the potential to exceed $10.7 million in gross margin per year.

6.2.10 In the RP-2003-0203 Decision concerning the Enbridge 2005 Test Year, the Board ruled that a 75:25 ratepayer to shareholder ratio was appropriate for amounts greater than the forecast gross margin of $10.7 million. In light of the fact that this ruling was handed down relatively recently, and in consideration of the evidence in this case, the Board sees no compelling reason why the current mechanism and amounts should be altered.

6.2.11 The Board, however, does see merit in providing for the Company's TS O&M costs to be reimbursed by ratepayers in 2006. As indicated above, the Board regards the optimization of the surplus assets to be an obligation of the Company. In consideration of this, and in light of the benefits the ratepayers realize, the Board finds that it is appropriate that the associated O&M costs be recovered from ratepayers. The Company has stated that this cost will be $800,000 in 2006, and the Board accepts this amount. The Board notes that there is a deduction of $800,000, related to TS costs, in the Company's statement of Other Operating Revenue. The Board therefore assumes that the $800,000 deduction reflects Enbridge's presumption that the Board would find as it has. If that is not so, an appropriate adjustment shall be made to the Company's revenue requirement to reflect the Board's finding.

6.2.12 Finally, the Board would like to comment on the longevity of this sharing mechanism. The Board views a TS sharing mechanism such as this as something that should endure for more than a single year. Indeed, the Company's proposal alluded to a mechanism for 2006 "and beyond". The Board does not see merit in arguing this issue year after year unless there is a fundamental shift in the TS marketplace. Therefore, the Board encourages Enbridge and the parties to adopt this methodology beyond 2006 unless a change is necessitated as a result of conclusions reached in the Natural Gas Electricity Interface Review.

7. CUSTOMER SUPPORT COSTS (INCLUDING CUSTOMER CARE AND CUSTOMER INFORMATION SYSTEM)

7.1 BACKGROUND

7.1.1 Enbridge is seeking approval for total 2006 customer care/CIS costs of $119.4 million (the original amount of $122.2 million was reduced to reflect the negotiation of the new CIS agreement). Of this total, $18.1 million is related to CIS, $85.6 million is related to outsourced customer care services, and the balance is related to department operating costs, the provision for bad debts, or uncollectibles, interest on security deposits and the non-utility elimination.

7.1.2 Enbridge originally contracted with Enbridge Commercial Services Inc. ("ECSI") in 2000 for customer care services. Effective January 1, 2002, that contract was assigned to CustomerWorks LP ("CWLP"), which is a limited partnership between Enbridge Inc. and Terasen Inc., in which Enbridge Inc. holds a 70% interest and Terasen Inc. holds a 30% interest. The arrangement governing the limited partnership affords Enbridge Inc. an option to acquire majority interest in the general partner of CWLP. The CIS asset is held by ECSI and licensed to CWLP, and the fee is fixed for 2005, 2006, and 2007 at $8.3 million per year.

7.1.3 CWLP subsequently entered into an agreement with Accenture pursuant to which assets and personnel were moved to Accenture. Accenture delivers the services to CWLP's clients. Neither ECSI nor CWLP have retained employees to any significant degree.

7.1.4 The hearing focussed on three main agreements:

- The CIS Services Agreement between Enbridge and CWLP
- The Client Services Agreement between Enbridge and CWLP

- The Program Agreement between CWLP and Accenture

7.1.5 The prior CIS Services Agreement between Enbridge and CWLP expired September 30, 2005. Enbridge has entered into a new long-term agreement with CWLP, and it is seeking Board approval of the term of that new agreement. That issue is the subject of the next chapter.

7.1.6 The Client Services Agreement between Enbridge and CWLP expires on December 31, 2006. Under this agreement, CWLP has an obligation to identify and implement commercial opportunities to reduce costs. The Company identified a change in collection practices and the call centre fee schedule as areas where this provision has resulted in savings to Enbridge. No savings have been passed on as a result of the subsequent outsourcing to Accenture. Mr. Louth, Enbridge's external benchmarking witness, recommended that the Company tender this agreement before its expiry, noting that tendering such arrangements is one of the best ways to achieve fair market value.

7.1.7 The Customer Care Program Agreement was entered into by CWLP and Accenture, effective August, 2002. It covers CIS services and client services. The evidence relating to this agreement was treated as confidential and related testimony was heard *in camera*. The Board prefers that its findings be public, and we have therefore limited the description and analysis of the agreement, the related evidence and intervenor submissions. However, some aspects of the arrangements have been redacted at the insistence of CWLP and Accenture.

7.1.8 The Board has identified three issues which need to be examined in order to determine the appropriate level of costs for customer care and CIS services:

- Benchmarking
- Competitive market costs for Enbridge's services
- Rate of Return analysis for CWLP/ESCI

7.1.9 The Board also addresses the issue of interest on security deposits at the end of this chapter.

7.2 BENCHMARKING

7.2.1 Enbridge presented benchmarking evidence prepared by Donald Louth Associates Inc. ("DLAI") in support of its claim that its customer care/CIS costs are reasonable. The DLAI study, which was adapted and updated from an earlier study conducted for Direct Energy in Alberta, concluded that Enbridge's 2006 customer care/CIS costs are 7.9% above benchmark, which in Mr. Louth's own view is at the top end of the range of reasonableness. He also noted that the sample had a larger than expected standard deviation. Mr. Louth acknowledged that a review of the rate of return of the service provider would be another approach to the determination of the reasonableness of the costs, and that a market price comparison would be informative.

7.2.2 Enbridge also filed evidence comparing its costs with information gathered from TECC Group Inc.'s 2002 compilation of U.S. utilities, as reported to the Federal Energy Regulatory Commission and from PA Consulting Group's 2003 annual customer care cost survey.

7.2.3 Mr. Stephens appeared on behalf of IGUA, the Council, and VECC. He testified that it is preferable to conduct the benchmarking analysis using a small sample, with comprehensive study and normalization, and unit-by-unit cost comparisons. He could not identify an example of it being done this way, but he indicated that such an approach is being developed in Alberta. He asserted that an open tender is the preferred approach to determine fair market value. Mr. Louth acknowledged that Mr. Stephen's approach was appropriate, but would require more time and money to complete.

7.3 BOARD FINDINGS

7.3.1 VECC submitted that the benchmarks are flawed and do not give as true a picture of fair market value as CWLP's costs do. Specifically, VECC submitted that the TECC and PA studies are out of date and that the DLAI study is flawed in the following ways:

- The method used to account for the inflation of 2003 costs to 2006 levels is not statistically valid because it included utilities which were not in the original sample. If inflation was over-estimated in the study, then Enbridge's costs would be above the reasonable level.

- Because of the small sample and large standard deviation, Enbridge's costs could be 30% higher than the lowest in the "cluster" sample and still be considered reasonable.

- The analysis does not properly account for utility size, nor does it examine the impact of economies of scale.

7.3.2 VECC concluded that the study should be given little weight, particularly in comparison to the service provider cost analysis available for a direct assessment of market value.

7.3.3 Enbridge responded that VECC's (and other intervenors') dismissive attitude toward the benchmarking work was not grounded in the evidence. Enbridge submitted that benchmarking is a means of determining fair market value, and it continued to rely on the results of the three referenced benchmarking reports.

7.3.4 The Board agrees with VECC's characterization of the weaknesses of the DLAI study and therefore finds that the DLAI benchmarking study can not be relied upon to conclude that Enbridge's costs are reasonable. The PA and TECC studies are dated, and the Board therefore finds them of limited relevance when considering 2006 costs.

7.3.5 Enbridge argued that related decisions by the Alberta Energy and Utilities Board (AEUB) support the Company's position, namely that benchmarking is the right approach to establish fair market value and that the DLAI study meets the requirements of a comprehensive benchmark study. The Board notes that the AEUB, in its *Decision 2005-105*, dated September 13, 2005, recognized the limitations of benchmarking as a tool for assessing utility costs and emphasized that this is an evolving area, requiring cooperation amongst utilities and customers. Noting these concerns, the AEUB Board found that the DLAI study had some deficiencies but chose to accept it. The Board finds that the weaknesses of the DLAI study are amplified in the current case because it has been adapted from the original study, which had another entity and situation as its primary focus, and it has been revised, somewhat crudely, to examine more current costs.

7.3.6 VECC submitted that the comparison between Enbridge and Terasen is noteworthy and shows that Enbridge's costs are too high. VECC submitted that the relevant difference is $2.37/customer, because including the 2006 CIS fee, which incorporates a reduction for the end of the life of the legacy CIS system, does not form the basis of a valid comparison. Given that Enbridge is three times the size of Terasen, VECC submitted that scale economies should result in lower costs to Enbridge and that the Company's claim that climatic conditions explain the difference is not borne out by the evidence.

7.3.7 Enbridge responded that the comparison to Terasen (then BC Gas) was a pivotal part of the Board's 2003 decision and that the difference between the two has now all but disappeared if the reduction in the CIS cost for 2006 is included. In Enbridge's view, VECC has unreasonably and artificially inflated the difference but even so can still only derive a difference of $7.34 million, which undermines the reasonableness of the other approaches which result in larger proposed adjustments.

7.3.8 The Board agrees that the comparison with Terasen is relevant, but it does not establish what an appropriate level of costs should be for Enbridge. The Board agrees that the reduction in CIS fees for 2006 may undermine the comparability of the figures. Similarly, climatic differences may explain some differences, as Enbridge has maintained, although the Board notes that Enbridge was not able to provide any comparative workload statistics to assess this claim. However, the Board agrees with VECC that scale economies should be observable and that none are apparent. The Board notes that the difficulties parties had in identifying appropriate comparators and adjusting for relevant differences shows that benchmarking cannot be advanced through cross-examination.

7.3.9 The Board continues to believe that there is value in benchmarking analysis as a tool in the determination of just and reasonable rates. Enbridge may wish to pursue further benchmarking studies in this area. However, given the substantial direct evidence available to the Board regarding the underlying costs, the Board will not order that a further benchmarking study be conducted in this area. If benchmarking is to be done, the Board notes that it would benefit from the involvement of intervenors.

7.4 COMPETITIVE MARKET COSTS OF SERVICES PROVIDED TO ENBRIDGE

7.4.1 The Program Agreement outlines how funds flow from CWLP to Accenture. Because this agreement was filed in confidence, and the testimony was heard *in camera*, the Board is severely limited in what it can provide in a public decision. The Board has chosen to provide a redacted version of the decision. This will alert interested persons and parties, particularly in the future, that there is additional relevant detail held in confidence at the Board. Parties will be able to apply to the Board for access to the unredacted decision for purposes of preparing for subsequent proceedings. Parties who signed the confidentiality agreement will have access to an unredacted version of this Chapter, but will have to return the document at the end of the proceeding (which is at the end of the appeal period).

7.4.2 [redacted].

7.5 BOARD FINDINGS

7.5.1 IGUA submitted that if a stand alone utility decided to spin off its customer care activity into an organization that would in turn provide services to the competitive market, it would obtain the same benefits as CWLP obtained in the Program Agreement. In IGUA's view, there is harm to ratepayers from the current Enbridge arrangement, [redacted]. IGUA further submitted that an in-house scenario was an invalid cost comparison for a service which is available in the competitive market.

7.5.2 CME made similar submissions, explaining that before transferring assets, human resources and expertise to a third party, which in turn intends to provide the services in the competitive market, a stand alone utility would ensure that the benefits from the arrangement exceeded its next best alternative. In CME's view, the terms would be the same as those contained in the contract between Accenture and CWLP, and the next best alternative would not be to continue to provide those services in-house, but rather to acquire them from a competitive service provider.

7.5.3 The Board agrees with this analysis to some extent. Enbridge has an obligation to acquire needed services in a cost-effective way, and the provision of customer care/CIS services is now available in the competitive marketplace. If Enbridge were a stand alone utility, it might well pursue moving its customer care assets and expertise into a competitive service provider. If it did so, it would be because there were tangible benefits compared to outsourcing the service but retaining the asset within the utility. In any event, the stand alone in-house option is not the most appropriate comparator in the current circumstances, and the Board finds that this comparator is of limited value in determining whether Enbridge's proposed cost level is reasonable.

7.5.4 IGUA submitted that the best measure of fair market value is the amount charged by a service provider operating in a competitive market pursuant to an arm's length contract. In its view, all other measures are mere indicators. IGUA noted that Mr. Stephens supported this approach.

7.5.5 With respect to the cost of other Customer Care Services, IGUA submitted that [redacted]. As a result, the contract between CWLP and Accenture is the best evidence that Enbridge's contract with CWLP is imprudent. IGUA concluded that the charges by Accenture to CWLP for the services provided to Enbridge represent fair market value, noting that Enbridge's witness Mr. Louth acknowledged the relevance of these amounts. [redacted]. IGUA noted that utility rate of return calculations for CWLP corroborate its conclusion regarding the fair market value approach.

7.5.6 IGUA's submissions were echoed and/or supported by CME, VECC, the Council and Schools. The Council noted that whereas typically the Board has had difficulty determining fair market value, it now has that information through the evidence of Accenture's charges to CWLP.

7.5.7 Enbridge responded that the intervenors' claim that the amounts paid by CWLP to Accenture represent fair market value, were based on a faulty premise. Enbridge submitted that the Program Agreement is more than a mere outsourcing arrangement and that therefore the amounts paid by CWLP to Accenture were not representative of the fair market value of customer care and CIS services.

7.5.8 The Board finds that the cost which CWLP pays to Accenture for the provision of customer care/CIS services to Enbridge is a relevant consideration in the determination of the reasonableness of Enbridge's costs. The analysis prepared by IGUA assumes that the benefits which CWLP receives through the operation of the Program Agreement could have been achieved by Enbridge contracting on its own. The issue the Board must consider is whether the Program Agreement represents an arrangement which Enbridge could have procured for itself independently. The Board is not convinced that Enbridge would have been in a position to achieve all of the benefits which CWLP has achieved through the Program Agreement, but the Board is convinced that Enbridge could reasonably have expected to achieve some of the benefits.

7.5.9 In effect, EI decided to enter the competitive customer care/CIS business and it used its regulated utility business to underwrite the costs of that business venture. [redacted]

[redacted]. Enbridge could reasonably have expected to achieve benefits, [redacted], if it entered into an arrangement directly.

7.5.10 The Board notes its findings in RP-2001-0032 in which it referred to the same position argued by Enbridge in this case, namely that ratepayers will benefit from economies of scale but cost efficiencies are to the account of the affiliate. In that case the Board found that it expected to see evidence of scale benefits, along with improvements in service quality, service reliability and security of supply. [redacted]

7.5.11 The Board concludes that the evidence demonstrates that [redacted] the costs to Enbridge in the CWLP agreement are higher than fair market value. However, the Board does not agree that an adjustment of [redacted] as calculated and proposed by IGUA and others is justified. The Board finds that it is appropriate to consider the rate of return for CWLP to determine the appropriate cost allowance, and we address that issue next.

7.6 RATE OF RETURN FOR ECSI AND CWLP

7.6.1 Quite a number of exhibits were filed which purported to calculate the returns of CWLP and ECSI. Issues arose as to the proper allocation to Enbridge and others and the appropriate components of rate base. Enbridge presented an analysis of CWLP and ECSI's earnings for 2006 in line with the approach taken by the Board in 2003. [redacted].

7.7 BOARD FINDINGS

7.7.1 Schools supported IGUA's approach regarding the relevance of the costs arising from the Program Agreement, but preferred an analysis of costs and returns, noting that its analysis results in a similar level of disallowance. In Schools' view, this approach identifies excess returns of between [redacted] and [redacted], and that [redacted] should be disallowed.

7.7.2 Enbridge responded that under the Affiliate Relationships Code (ARC), costs for the service provider are relevant when there is no reasonably competitive market, but not when there is a market. In Enbridge's view, the Board should not examine the costs to the service provider. The Board does not agree. Enbridge is correct that where a competitive market exists, the ARC identifies that market value is the relevant method of assessment. However, the ARC identifies a fair and open competitive tender as the means by which market value is to be determined. That has not taken place in this case. In the absence of an open and fair competitive tender, the Board must consider other approaches. As set out above, the DLAI benchmarking study is of limited value, and therefore the Board has no robust benchmarking analysis which establishes fair market value. It is therefore appropriate to review the underlying costs, as was done in past Board decisions.

7.7.3 Enbridge also submitted that there is no evidence that the result of the rate of return calculation is related to an assessment of fair market value. The Board does not find that the return calculation must be related to fair market value. That is not the purpose of the analysis. The purpose of the analysis is in relation to the standard that Enbridge should pay no more than the fully allocated cost of the service, including a reasonable return on invested capital.

7.7.4 It is not the Board's intention to perform a definitive analysis for purposes of this proceeding. The Board will lay out how it believes this analysis can usefully be performed and expects the Company to provide a similar analysis at its next rates case. However, it may be that further refinements can and should be made after further assessment, and the Board acknowledges that other analyses may be relevant for future reviews.

7.7.5 Schools developed calculations of return on rate base and return on equity for both CWLP and ECSI. The primary differences between Schools' calculations and those of Enbridge are in setting the relevant amount of rate base and the overall attribution basis to determine the impact attributable to Enbridge. In Schools' view, the return should be calculated in the same way as if the entity were regulated and that therefore the rate base should not include cash, accounts receivable, or start-up costs. Schools also removed assets under construction, but included a working capital allowance equivalent to one month of expenses. Schools did not use a revenue-based attribution to calculate the relevant portion for Enbridge. The result of Schools' analysis is a return which is [redacted] in excess of the return which would apply to the utility. Using a return on equity approach, Schools calculated an excess return of [redacted].

7.7.6 Schools performed a similar analysis for ECSI and calculated a sufficiency of [redacted] based on a return on rate base approach and a sufficiency of [redacted] based on a return on equity approach. Schools submitted that it preferred the ECSI measure because it includes all aspects and is less complicated, and concluded that the Board should disallow [redacted].

7.7.7 Enbridge did not accept Schools' approach and submitted that the Board recognized in its RP-2001-0032 decision that the service provider would expect a higher return than a regulated return. Enbridge also submitted that:

- CWLP is a competitive business and does not have a utility rate base;
- CWLP's return is measured as a percent of invested capital; and,
- CWLP's working capital requirements are driven by the Program Agreement.

7.7.8 Enbridge also maintained that the Board should do the analysis from the perspective of ECSI, because it is the entity which holds the CIS asset and where all the Enbridge transactions are consolidated.

7.7.9 The Board does not agree. The purpose of the return analysis is to examine the costs and returns of the service provider. The fact that ECSI is the entity which holds Enbridge Inc.'s interest in CWLP does not make it the relevant point of analysis. CWLP is the service provider, not ECSI, and therefore CWLP is the relevant point of analysis. [redacted]. The Board finds that the best proxy for fully allocated costs is determined through performing a rate of return analysis of CWLP, subject to an appropriate allocation to Enbridge.

7.7.10 The Board does not accept the approach proposed by Schools because it attempts to derive a utility-equivalent return calculation, and that is not the purpose of this analysis. The purpose of the analysis is to determine the allocated cost, including a return on investment. The Board agrees that the rate of return must be no higher than a utility equivalent, but the level of investment should reflect the service provider's actual position, appropriately allocated.

7.7.11 However, the Board also finds that Enbridge's various analyses are deficient. The difficulty is that much of what purports to be an analysis of CWLP is actually a form of analysis of ECSI, [redacted]. What is appropriate is an analysis of CWLP's income and assets allocated amongst its clients, not between its owners.

7.7.12 The Board believes that an analysis based on a simple attribution of CWLP net income and assets to Enbridge on the basis of Enbridge's revenues as a proportion of CWLP's total revenues is not unreasonable in the circumstances. On this basis, the overearnings (based on tax-loaded return of 9.5%) attributable to Enbridge are $14.8 million.

7.7.13 The Board acknowledges that a more refined analysis would recognize the following factors:

- [redacted].

- [redacted].

- [redacted].

- [redacted].

7.7.14 The Board is confident that if the more refined analysis described above were conducted, the resulting overearnings would be at least as great as under the more simplistic approach which has been adopted.

7.8 BOARD FINDINGS - CONCLUSIONS

7.8.1 In Enbridge's view, the level of disallowance proposed by intervenors cannot pass the "sanity check" because the resulting costs would be below the reasonable range in all the benchmarking data. In Enbridge's view, there is no evidence that it could serve customers at the resulting $40 per customer. Enbridge continued to rely on an in-house comparison to substantiate that customer care costs would be higher, but for the outsourcing.

7.8.2 In conclusion the Board finds that:

- The escalated in-house cost is not the appropriate comparator in this instance; the competitive alternative is an appropriate comparator.

- The benchmarking evidence is of limited value.

- There is evidence that benefits [redacted], which Enbridge could reasonably have achieved if it had gone directly to the competitive market.

- The return analysis indicates that the service provider is earning $14.8 million in excess of its costs to provide service to Enbridge.

- If there is a disallowance of $14.8 million, the resulting cost per customer is $49.58.

7.8.3 As a result, the Board will disallow $14.8 million from the proposed total customer care and CIS costs of $103.7 million.

7.8.4 As in past proceedings, disclosure was contentious in this proceeding. Inaccurate documents were filed and it took multiple rounds of requests, refusals and subsequent Board directions to get the relevant cost data and return analyses on the record. The process of disclosure on this issue was time consuming and inefficient and detracted from the overall proceeding.

7.8.5 The Board is not inclined to engage in lengthy analysis and comment on this issue; it has done so in the past in order to provide guidance, but to little avail. Instead the Board will be prescriptive and will direct what material Enbridge is to include in its pre-filed evidence at its next rates case. The Board therefore directs Enbridge to file the following as part of its next rates case:

- All agreements between Enbridge and CWLP, ECSI or any other EI-related entity related to the provision of customer care or CIS

- The Program Agreement between CWLP and Accenture, including any amendments or revisions

- Financial statements for ECSI and CWLP (historical, bridge and test year)

- The return analyses described in this Decision

7.9 INTEREST ON SECURITY DEPOSITS

7.9.1 Enbridge’s total claim for customer support costs includes $1.8 million for interest on security deposits. The interest is calculated using the Board-approved short term interest rates. During the oral proceeding, Enbridge filed an undertaking response to update its interest on security deposits calculation using the short term rates agreed to in the 2006 Settlement Proposal. The interest rates prescribed in the 2006 Settlement Proposal are lower than the interest rates used in the pre-filed evidence. Based on the response to the undertaking, Enbridge should reduce its customer support costs by a further $500,000.

7.9.2 The total Board approved customer support costs will therefore be $119.4 million less $14.8 million and less $0.5 million, or $104.1 million.

8. CIS REPLACEMENT CONTRACT

8.1 BACKGROUND

8.1.1 Enbridge is seeking Board approval for the term of its new contract for CIS services and for the associated costs in 2006. The Board has addressed the issue of CIS costs in the prior chapter on customer support costs. In this section, we will address the issue of the new CIS contract.

8.1.2 The existing CIS Services Agreement with CWLP expired on September 30, 2005. The new CIS Services Agreement with CWLP is for a term of 12 years 3 months, beginning October 1, 2005. As part of the agreement, CWLP will tender for a new CIS system. The service fees will be based on the tendered package and will include a return component equivalent to what the return would be if the asset were in rate base. Enbridge maintained that it could not tender directly as there is a two year lead time to put the CIS in place and it had to ensure the provision of CIS services through that lead time.

8.1.3 Enbridge intends to implement a standard SAP package solution, and although CWLP will own the system, Enbridge maintained that it could hire another party to run the system when its Client Services Agreement expires at the end of 2006. The new system is to be in place beginning 2008; the existing system will be used until then. The CIS contract is contingent on Board approval of the new CIS costs. If the costs are not approved then the legacy CIS system will continue to be used; the fees will be reduced by 50%, and the contract will expire at the end of 2008.

8.1.4 The Board has identified the following issues:

- Is a new CIS system required?
- Has Enbridge gone about acquiring a new CIS system appropriately?

- Is the fee structure in the contract prudent?

- Are the other terms and conditions of the contract appropriate?

8.2 IS A NEW CIS SYSTEM REQUIRED?

8.2.1 Enbridge testified that the current CIS system is inflexible and costly to update. Enbridge has selected SAP, and will now undertake an RFP process through CWLP to select a system integrator. Enbridge estimated that the new system will have a positive net present value of approximately $11 million. Enbridge noted that while it did not fully understand all of the requirements of the Gas Distribution Access Rule, it would ensure that the new system can accommodate the new environment created by the Rule.

8.2.2 Enbridge's advisor, Mr. Dick of MiCon, confirmed the need to replace the CIS system and the benefits of an SAP solution. He also acknowledged that it will be a system which others may want to use. Mr. Stephens, witness for the Council, IGUA and VECC, accepted that the CIS system needs to be replaced.

8.3 BOARD FINDINGS

8.3.1 The Board notes that no party took the position that the CIS system should not be replaced. The Board accepts that a new CIS system is required and that a package approach appears sensible.

8.4 HAS ENBRIDGE GONE ABOUT ACQUIRING A NEW CIS SYSTEM APPROPRIATELY?

8.4.1 According to its proposal, Enbridge will not be tendering directly for the new CIS system. Rather, the tender will be done through CWLP, which will hold the asset. The tender was to have been conducted in October and the evaluation is to be concluded in January. Enbridge explained its approach as a move to tendering, but within the CWLP envelope. In its view, the CWLP tender, which MiCon will oversee and assess, will provide market validation.

8.4.2 Enbridge identified three rationales for this approach:

- If the CIS system is held outside Enbridge, then bill access can be provided to other parties. Otherwise, Enbridge believed it was precluded from offering billing services pursuant to its Undertakings to the Lieutenant Governor in Council. This sharing of the bill currently provides $5 million in benefits to ratepayers.

- The CIS contract, in Enbridge's view, effectively caps the capital expenditure at $79.4 million, but makes provision for the sharing of any cost savings greater than 5%.

- The fees will be based directly on costs and will include a utility-equivalent return component.

8.5 BOARD FINDINGS

8.5.1 The Council submitted that although the Board is only being asked to approve the term of the contract, it must consider whether the substance of the contract is prudent or imprudent. In the Council's view, the contract should be found to be imprudent, and Enbridge should be directed to tender for CIS services directly. The Council noted that there was no evidence that Enbridge's management ever considered putting the business out to tender, notwithstanding the Board's comments in its RP-2002-0133 Decision. VECC submitted that the appropriate way to mitigate the IT development risk is through a third party with an appropriately structured commercial contract.

8.5.2 Enbridge responded that CWLP will conduct a fair and open tender and that there is no compelling case to be made to suggest that the tender should be done directly by Enbridge. In Enbridge's view there should be no concern because the results of the tender will be available to the Board.

8.5.3 The Board finds that the three main rationales which Enbridge has advanced could equally have been achieved through a direct tender. The Board notes that Enbridge did not even consider the option of seeking an exemption from its Undertakings with respect to third party bill access. The Board understands the Company's concern regarding utility involvement in competitive activities, but the Company appears to have failed to consider any alternative approaches to this issue. (The issue of third party access to the Enbridge bill is addressed in the next chapter.) The Board also agrees with VECC that a direct tender would provide the appropriate structure to manage the cost risk and to ensure competitive pricing.

8.5.4 Schools submitted the contract should not be approved, largely because it was not tendered and therefore the Board cannot know if it represents fair market value. IGUA submitted that the Board should not do anything which endorses or excuses Enbridge's refusal to tender, and that therefore the contract should not be approved.

8.5.5 The Board has already expressed in prior decisions its strong preference for competitive tendering in situations such as these. The Board concludes that Enbridge could have tendered its CIS service requirements in this case, perhaps with interim arrangements with CWLP using the legacy CIS system until the new CIS is in place. The Board shares the concerns of intervenors that it appears that broader corporate concerns have reduced the focus on maximizing benefits to Enbridge and its ratepayers.

8.5.6 The Board concludes that Enbridge should have tendered directly, but this factor on its own is not grounds to deny approval of the contract. However, because it was not tendered directly, Enbridge must find other means to demonstrate that the arrangement is prudent.

8.5.7 Superior submitted that if the Board approves the contract, such approval should be conditional on the Company making all related party relationships and contracts open, transparent and compliant with the spirit and intent of the ARC and subject to review and disclosure. The Board agrees that if Enbridge does not tender directly, there must be requirements related to disclosure. For example, a future panel of the Board will probably have to examine the contract between the CIS provider and CWLP in the same way it has examined the Program Agreement between CWLP and Accenture in this case.

8.6 IS THE FEE STRUCTURE IN THE CONTRACT PRUDENT?

8.6.1 The fees are structured such that Enbridge pays all the capital and operating costs of the new CIS system using a cost-based utility approach. Enbridge explained that the fees in the contract are based on estimates which will be revised after the tender is complete, but that they will vary only with customer numbers, volume or activity level. Enbridge emphasized the value of the capital expenditure "cap" of $79.4 million.

8.6.2 Ms. Williams, witness for IGUA, the Council and VECC, testified that there were serious shortcomings in the contract, including the fact that there are no provisions for gain-sharing, most-favoured nation pricing, or fee benchmarking, and that Enbridge is liable for certain incremental costs related to test databases and client training databases.

8.7 BOARD FINDINGS

8.7.1 The Council submitted that the contract is imprudent for a number of reasons, including the fact that the service fees are not known with certainty and Enbridge is exposed to additional costs. The Council notes that under the arrangement, Enbridge has no opportunity for fee reductions from additional clients, gain-sharing, most-favoured nation pricing, or benchmarking. CME submitted that a cost-based fee does not provide Enbridge with the benefits of a negotiated fee which takes account of efficiency benefits arising from the system being used by others.

8.7.2 Enbridge responded that the arrangement provides special protection for ratepayers in that the fees are structured to allow CWLP to earn the same return that would have been earned if the assets were owned by Enbridge. The Company submitted that benchmarking would result in higher fees and that gain-sharing and most-favoured nation provisions are not applicable, given that the fee structure is based on a cost-plus approach with a cap, and the return is based on a utility approach.

8.7.3 The Board agrees with intervenors that Enbridge's ratepayers are entitled to the benefits which flow from the efficient use of Enbridge's assets, and the transfer of an asset to another party does not necessarily eliminate that entitlement. One of the primary reasons for outsourcing is to achieve a lower cost solution than the in-house alternative. Therefore, as identified elsewhere in this decision, the appropriate standard of comparison is not what Enbridge would pay on a stand alone basis for a dedicated asset, but rather what the market price would be through a third party provider. Therefore, Enbridge's assertion that the fees are prudent because they are based on a utility cost equivalent is not correct, because the appropriate basis of comparison is not a stand alone in-house equivalent. As a result, the Board is not convinced that a fee structure based on the in-house alternative demonstrates that the fee structure is prudent. The evidence of Ms. Williams supports the conclusion that a direct competitive tender would yield a different fee-setting approach which would incorporate elements such as gain-sharing, benchmarking and most-favoured nation pricing, as well as fee reductions arising from the addition of other clients.

8.7.4 The Board notes that Mr. Dick acknowledged that Enbridge is paying CWLP to develop a product which CWLP can then use for other clients. In his view, this was fair because Enbridge does not take the risk that there might be a loss associated with the project. The Board does not agree. In essence, the arrangement removes most of the risk of loss for CWLP because the most substantial part of the cost will be covered by Enbridge. It is not apparent to the Board that the requirement to incur incremental costs to add clients adds any substantial risk. The Board agrees with intervenors, and Ms. Williams, that if an entity entered into a competitive arrangement it would expect to achieve some of the benefits of other clients using the system.

8.7.5 CME noted that without a most-favoured nation clause, CWLP can charge other clients more competitive prices, and Enbridge will have covered all of the basic costs. The Board agrees, and notes that if this sort of pricing were to occur it would be contrary to the objective of precluding utilities from competitive activities, which is to prevent the cross-subsidy of competitive businesses by utility ratepayers.

8.7.6 Most intervenors took issue with the claimed capital expenditure cap, pointing out that it is not explicit in the contract. Enbridge submitted that the benefit of the capital expenditure cap was substantial and that the provision was seen as very positive by Mr.

Dick and that Ms. Williams agreed it would be valuable to have protection from the risk of cost overruns. IGUA submitted that the capital expenditure "cap" will distort bidding, although Enbridge disagreed. The Board notes that Mr. Dick acknowledged that by identifying the cap in a public way, CWLP may well have mitigated the risk of the capital cost being higher while ensuring that the necessary functionality will be included. He also agreed that the wording regarding the cap should be firmer, and Ms. Williams took this position as well. The Board concludes that the wording of the contract does not support Enbridge's claim regarding the firmness of the cap. However, even if the cap is firm, the Board does not believe that it represents a sufficient tangible benefit to ratepayers so as to warrant approving the contract.

8.7.7 The Board finds that the fee structure is not just and reasonable for the purposes of ratemaking. As the Board has stated elsewhere, this type of arrangement must exhibit tangible benefits to ratepayers. The only such apparent benefit is the cap, and it is tenuous at best.

8.8 ARE THE OTHER TERMS AND CONDITIONS OF THE CONTRACT APPROPRIATE?

8.8.1 Ms Williams identified a number of areas in which she concluded that the contract contained significant risks for Enbridge, but in her view the key shortcomings were:

- the inability to terminate in the first 7 years – especially given the 12 year term;
- performance risks due to the weak service levels, the lack of financial penalties, and the long termination period; and
- technological risks due to lack of description of what is to be provided and the lack of any obligations to consider or incorporate technological changes.

8.8.2 Mr. Dick, Enbridge's witness, agreed that the timing to address service level shortcomings should be shorter and that the 7 year lock-in is not reasonable.

8.9 BOARD FINDINGS

8.9.1 The Council submitted that the contract is imprudent for all the reasons identified by Ms. Williams in her evidence. Schools submitted that the contract should not be approved, in part because the software has not been identified and the functional specifications and actual CIS deliverer are unknown. VECC submitted that the Board should direct Enbridge to include the contractual features recommended by Ms. Williams in a competitively tendered contract.

8.9.2 OESC submitted that by locking in the CIS replacement system to a 12 year term, Enbridge runs the risk of finding the new system outdated and inflexible to meet changing requirements before the expiry of the agreement. OESC proposed a term of 6 or 7 years with a renewal provision. Enbridge submitted that the CIS Agreement must allow for unforeseen events, and that therefore it should be viewed as providing a framework and process to achieve objectives. In Enbridge's view the scope is unambiguous, but has flexibility, and the system will meet all Enbridge's needs for the foreseeable future, including implementation of GDAR.

8.9.3 The Board agrees with the parties who have identified the serious shortcomings in the contract related to the termination, performance and technology provisions. The Board recognizes that there is give and take in any negotiation and concludes that each of these shortcomings on its own does not make the contract imprudent. It is the cumulative effect of these provisions which concerns the Board.

8.9.4 Enbridge has the onus to demonstrate that these provisions are reasonable. It has failed to do so. First, it has been unable to identify any significant benefits flowing from the contract (other than the capital expenditure cap, which is discussed above) which would warrant the severe limitation of a 7 year lock-in period. Second, the provisions related to performance place the burden of any service shortfalls on Enbridge by allowing CWLP significant time to improve the performance, rather than placing a financial incentive on CWLP to address the problem promptly. Finally, although Enbridge has asserted that the system will meet its requirements for the foreseeable future, the Board is of the view that a term of over 12 years extends beyond the period of "foreseeable" future, and therefore the contract must in some way address the potential for unforeseen technological developments.

8.10 CONCLUSION ON NEW CIS CONTRACT

8.10.1 The Board will not approve the 12 year term of the new CIS contract. Enbridge may choose to address this issue in two ways. The Board's preferred approach is for Enbridge to undertake a direct competitive tender for the new CIS. Alternatively, if Enbridge intends to continue its relationship with CWLP for the new CIS, it will be required to demonstrate that the contract is prudent and incorporates tangible benefits for ratepayers. It can also expect to have to disclose the contract(s) between CWLP and the CIS provider in order to substantiate that the arrangements between CWLP and Enbridge reflect what is available in the market.

9. THIRD PARTY ACCESS TO CUSTOMER BILLS

9.1 BACKGROUND

9.1.1 Third Party Access to customer bills was included on the Issues List, but the Board indicated that its scope would not include billing on behalf of commodity providers, known as ABC-T billing service. Enbridge did not file evidence with respect to this issue, but it did respond to related interrogatories and indicated that it was supportive of providing access to the bill for third parties.

9.1.2 Under the current arrangements, Enbridge and Direct Energy Essential Home Services ("DEEHS") share access to a bill which is prepared by Accenture under contract to CWLP and bears the Enbridge logo. DEEHS had exclusive access to this bill until December 31, 2005, but there are additional non-competition provisions in place which effectively extend this exclusivity until May 2006.

9.1.3 DEEHS and Enbridge each have separate arrangements with CWLP. Under Enbridge's arrangement, for every bill which is shared, the cost of the bill is reduced by half. There are no additional savings if the bill is shared by more than two parties. The current value of this arrangement is approximately $5 million per year because DEEHS has approximately 1.2 million customers. Details of the arrangement between DEEHS and CWLP were not disclosed in the proceeding, but Enbridge did file a letter of agreement between Enbridge Inc. and DEEHS regarding the extension of DEEHS' Client Services Agreement for a period of 4 years, subject to conditions to terminate.

9.1.4 The Board has identified two specific issues:

- Should third party service providers have access to the bill?
- If so, when should access be provided?

9.2 SHOULD THIRD PARTY SERVICE PROVIDERS HAVE ACCESS TO THE BILL?

9.2.1 Enbridge was of the view that it is precluded from offering billing services directly, and as a result, any on-bill financing would have to be done through an affiliate. Enbridge took the position that the Undertakings it had given to the Lieutenant Governor in Council at the time of the purchase of the shares of the Company by IPL prohibited it from engaging in competitive activities. In Enbridge's view that includes billing, although it acknowledged that the Board can grant exemptions to these Undertakings and that exemptions were granted for ABC-T billing.

9.2.2 Enbridge explained that its charges appear on the Enbridge Inc. bill, and that therefore the Company does not have contractual control over access to the bill by third parties. Enbridge does exercise some control over the bill's content in that it reviews the DEEHS inserts before they are included in the bill. The Company also acknowledged that it can facilitate and influence access to the bill; indeed it explained that it was making efforts to find partners for the bill, primarily as a means of increasing the penetration of natural gas appliances and products, not particularly to reduce the cost of billing.

9.3 BOARD FINDINGS

9.3.1 DEEHS submitted that the Board does not have the jurisdiction to make an order or grant remedies concerning billing arrangements related to non-commodity services and products. To the contrary, in the Board's view, Enbridge must maintain and demonstrate effective control over its billing and any sharing which takes place on the bill it uses. The Board does have jurisdiction over the regulated activities of Enbridge, including how Enbridge charges for its services and its billing arrangements. This view has been upheld by the Court of Appeal in its September 2004 decision regarding the Gas Distribution Access Rule. The contractual relationships may have been organized such that Enbridge does not provide the billing services directly; it purchases the service from CWLP. However, this is essentially a utility bill. The value which others derive from sharing access to the bill is associated with sharing access with utility charges. This was recognized by most parties. The Board intends to continue to exercise its jurisdiction in this area.

9.3.2 Superior and OESC both submitted that the bill should be open to all parties, including all marketers and other energy service providers. CME took the same position and noted that, from a policy perspective, access should be non-preferential because the bill relates to the charges of a regulated monopoly. HVAC also submitted that access should be available.

9.3.3 The Council submitted that while it supports facilitating competition and enhancing customer service, there must be clear benefits for ratepayers. In the Council's view, the full costs and benefits of bill access were not adequately explored, including the value of the Enbridge name and reputation. It also pointed to possible customer confusion regarding the relationship between Enbridge and third parties. The Council did submit that exclusive arrangements such as DEEHS' should be prohibited going forward.

9.3.4 DEEHS submitted that it is not reasonable for the intervenors to request orders other than those related to just and reasonable rates and that accordingly it is not reasonable for intervenors to ask the Board to change the current billing arrangements in the absence of evidence regarding the impact on ratepayers.

9.3.5 The Board agrees that there should be clear ratepayer benefits associated with shared access to the bill, but the Board is also concerned with broader public interest factors. In this latter area, the evidence was not definitive. While there may be benefits in terms of facilitating the purchase, financing or renting of gas appliances, there may be adverse consequences arising from customer confusion. Enbridge submitted that an ABC-type billing arrangement for service providers is not in customers' interest and identified various policy considerations, including questions respecting the ownership of the receivables, how to respond to customer disputes, the responsibility for the costs of extra calls and bad debt, and the impact on the Enbridge brand. Issues of this type would be raised in any sort of bill sharing arrangement, and the Board is therefore not convinced that there is a significant positive net benefit to ratepayers arising from shared access to the bill.

9.3.6 The Board concludes that there may be merit in sharing the bill with service providers, but in the absence of a specific proposal which addresses the issues raised by the Council and Enbridge, this cannot be concluded definitively. Enbridge's evidence regarding its potential course of action for third party access did not represent a fully formed plan and therefore is insufficient for purposes of Board approval. The Board finds that Enbridge must make a more thorough case before the Board is prepared to allow it to bill for its services in a shared environment. Specifically, Enbridge, if it wishes to pursue this initiative, must bring forward evidence on the various policy and financial issues and demonstrate that there are significant net benefits for ratepayers.

9.4 WHEN SHOULD ACCESS BE PROVIDED?

9.4.1 Enbridge estimated that it would cost $3.5 million to make changes to the current CIS system to provide for further third party access to the bill and that the change would take at least 12 to 16 months to complete. Enbridge concluded that it would be more cost effective to wait for the new CIS system to be put in place, because it is expected that it will be flexible enough to allow for this activity. Enbridge reported that it is exploring possible interim solutions; for example, providing on-bill financing through an affiliate or through a third party financing company. Under the latter scenario, there would be a separate bill, but it would bear the same brand as the Enbridge bill.

9.5 BOARD FINDINGS

9.5.1 OESC submitted that access should be provided effective June 1, 2006, and if not, then access for DEEHS should cease. Specifically, OESC submitted that gas marketers/retailers should have access to the invoice for the placement of corporate logos and targeted messaging. Superior made similar submissions, namely that access should be provided immediately, and if not, the DEEHS logo and billing inserts should be removed until all third parties are provided with similar access. DEEHS submitted that the Board does not have jurisdiction to order that DEEHS no longer have access to the bill, and noted that this would result in the loss of $5 million in cost savings for ratepayers.

9.5.2 HVAC submitted that under the current arrangements with DEEHS, the bill sharing is essentially exclusive, because the ability to accommodate others is very limited until the new CIS system is in place. In HVAC's view, all parties should have equal access or access should be restricted until equal access is available. HVAC made a number of recommendations. First, if DEEHS is not removed from the bill, then there should be restrictions, namely removing the logo, restricting the text, moving its section to a less prominent place, ending bill inserts, and providing a disclaimer regarding the relationship between Enbridge and DEEHS. HVAC also made recommendations as to how access by third parties should be provided and suggested that for the longer term, various protocols and principles should be developed to govern the access of third parties to the Enbridge bill.

9.5.3 Enbridge responded that the new arrangement with DEEHS is not exclusive and that CWLP and EI are open to negotiations with other service providers, but that any such arrangement must be a commercially sound transaction.

9.5.4 The Board does agree that any bill access which is provided should be on a non-discriminatory basis, because the access is linked with the provision of a regulated service, namely the billing of utility services. Under the current arrangements, DEEHS will continue to have effectively exclusive access. This is not appropriate, and must not continue. If Enbridge does not come forward with a comprehensive proposal regarding non-discriminatory shared bill access, then Enbridge must make arrangements for a stand-alone bill. The Board understands that if Enbridge bills on a stand-alone basis this will eliminate the cost benefit to ratepayers arising from the bill sharing, but the Board is prepared to accept this result.

9.5.5 In light of the Board's findings and the current arrangements with DEEHS, the Board finds it is appropriate to make provision for an adequate transition period. The Board will not require that any change be made immediately. However, as part of its 2007 rates case Enbridge must either come forward with a complete proposal regarding third party access or it must set out how it intends to ensure that its billing is separated from the billing of DEEHS by no later than January 1, 2007.

9.5.6 The Board agrees that it does not appear to be practical to upgrade the current CIS system for purposes of providing third party access. It would not be appropriate for ratepayers to bear this cost, and it appears unlikely that third party service providers would find this approach cost effective. However, if there is to be bill sharing, the Board does not believe that it is appropriate for third parties to be required to wait for the new CIS system to be implemented in 2008 before they are able to gain access to the bill. Enbridge has indicated that it is attempting to develop an interim solution. The Board would expect some form of interim solution to be part of any comprehensive proposal brought to the Board as part of the 2007 rates case.

9.5.7 In this decision, the Board has addressed access to the bill by service providers, not gas marketers. Some parties submitted that access provisions should be extended to gas marketers as well, but arrangements for marketers were specifically excluded from the scope of this issue, and are governed in any event by the Gas Distribution Access Rule. The Board has therefore not addressed that aspect of this issue in this decision.

10. CORPORATE COST ALLOCATION

10.1 BACKGROUND

10.1.1 Corporate Cost Allocation refers to the allocation of costs from Enbridge Inc. ("EI") to Enbridge for services provided by the parent to the subsidiary. The cost allocation methodology is governed by an agreement between EI and Enbridge and the Affiliate Relationship Code for Gas Utilities. Enbridge is seeking Board approval to recover $21.3 million for the 2006 corporate cost allocation and the Board's determination that the RCAM allocates costs for corporate services to Enbridge appropriately.

10.1.2 Enbridge has been receiving shared corporate services from EI for several years. The first time the Company brought forward a formal cost allocation methodology ("CAM") for consideration by the Board was in the RP-2002-0133 case, to set rates for the Company's 2003 test year. The Company sought recovery of $21.8 million for corporate cost allocations in that proceeding. Enbridge submitted an Ernst & Young report in support of the new methodology and argued that the methodology took into consideration the cost driver approach and principles of cost causality set out in the Board's Decision in EBRO 493/494[1].

10.1.3 The costs resulting from the application of CAM were settled as part of the "O&M envelope", and the Board considered only the policy aspects of the corporate cost allocation issue at the hearing. The Board, in its decision, found that the Ernst & Young review was too narrow and lacked a thorough analysis of how costs were being allocated. In its decision the Board directed Enbridge to obtain an independent review of the corporate cost allocation methodology and the inter-company services agreement.

[1] The primary criteria used to assess allocated costs were established in the Board's decision regarding Westcoast's charges to Union Gas Limited and Centra in 1997 (EBRO 493/494). In this decision, the Board laid out the three-prong test (Cost incurrence, Cost allocation and Cost/Benefit) according to which all corporate costs should be evaluated.

10.1.4 Enbridge, in consultation with the intervenors, engaged Deloitte & Touche ("Deloitte") to conduct an independent evaluation of CAM. Deloitte's report was filed as part of the RP-2003-0203 rate case. One of the primary recommendations in the report was that a service-based cost allocation methodology should be developed. This was in contrast to the CAM methodology, which was based on EI's departmental budgets. Based on its review, Deloitte recommended $13.5 million for recovery in rates, as compared with the Company's proposed $22 million. Enbridge filed reply evidence setting out its concerns about why the recommended amount was too low. Enbridge nonetheless accepted Deloitte's recommendations to modify the CAM to better align it with the Board's requirements.

10.1.5 As part of the 2006 rate case, Enbridge brought forward a new corporate cost allocation methodology called RCAM (Regulatory Cost Allocation Methodology). Enbridge retained Deloitte to develop the new service-based methodology in order to satisfy the Board's requirements. The intervenors were not involved in this exercise, although they did receive updates as the work was undertaken. The objective of the RCAM is to determine the costs EI should allocate to Enbridge for delivering required services during a given fiscal period. This RCAM does not replace CAM, the existing Corporate Cost Allocation Methodology, which will still be used by EI to transfer costs to all its affiliates, including Enbridge.

10.1.6 The history of Enbridge's proposed and approved levels of corporate cost allocation are set out below.

History of Corporate Cost Allocation

Fiscal Year	Proposed $ millions	Board Approved $ millions
1998	$ 1.3	$ 0.5
1999	$ 2.3	$ 1.9
2000	$ 5.2	$ 5.2
2001	$ 8.6	$ 8.6
2002	$ 11.6	$ 11.6
2003	$ 21.8	$ 21.8[1]

2005	$ 22.0	$ 13.5[2]

Notes: [1] The O&M expense envelope was settled and included the corporate cost allocation, but the policy issue was addressed in the hearing.
[2] The amount was agreed as part of the settlement proposal.

10.1.7 The following issues have been raised during the course of the proceeding:

- Is the RCAM methodology appropriate?
- Has the RCAM been appropriately applied?
- Does the 2005 Board approved amount form the appropriate base for consideration of the 2006 cost?
- Do the costs pass the 3-prong test?
- Should the Board be concerned that actual payments to EI will be in accordance with CAM – not RCAM?

10.2 IS THE RCAM METHODOLOGY APPROPRIATE?

10.2.1 VECC submitted that it was EI's objective to recover an amount as close to the CAM amount as possible, which is the amount EI will charge Enbridge in any event. In support of this position, VECC pointed out that the methodology is driven by EI with little input from Enbridge and the approach is not "demand pull"; rather it is EI-driven with Deloitte's support. VECC maintained that few revisions were made by Enbridge. VECC concluded that the RCAM as proposed should be rejected and that Enbridge should be directed to support any future claims for corporate costs by a service-based cost allocation methodology, and Enbridge should only procure from EI services that are not available in the market.

10.2.2 The Council submitted that the methodology reflects the interests of EI, not Enbridge. In the Council's view, the fact that RCAM comes up with the same amount as CAM is too extraordinary to be a coincidence. The Council asserts that the proposed RCAM methodology is not an adequate response to the Board's direction because the analysis should start with a determination as to whether services are actually needed by Enbridge. If the services are needed then a determination should be made as to whether they can be acquired at lower cost in the open market. The Council maintained that the RCAM process started with asking EI what it did, which in turn was confirmed by Enbridge. The Council noted that the reporting relationships between Enbridge and senior EI executives would compromise the credibility of that confirmation. The Council also submitted that there is no evidence to demonstrate that the costs allocated to Enbridge are reasonable or that they are less than what is available on open market.

10.2.3 Enbridge responded that a “demand-pull” approach would make no sense in the context of a shared services model because a high degree of planning and coordination is needed to ensure good governance and scale economies, and because the needs of other business units must be considered. EGD submitted that the use of a share services model imposes some constraints on negotiating modifications to services.

10.3 BOARD FINDINGS

10.3.1 With respect to the methodology being “EI-led” or “Enbridge-led” (or “supply push” or “demand pull” respectively), the Board agrees with intervenors that an Enbridge-led approach is more rigorous because it is a bottom-up demand led approach, rather than a top-down approach. However, an “EI-led” approach may be acceptable if there is evidence of rigorous review by Enbridge and an independent evaluation. The Board finds that the evidence does not support a conclusion that there was a rigorous review or an independent evaluation: there is limited evidence of adjustments being made to the services and very limited cost comparison to the “stand-alone” alternative. (This issue is also addressed in the 3-prong test section.)

10.3.2 The key factor in the Board’s analysis is the Primary Services, which are the descriptions of what EI does. Enbridge must be responsible for ensuring that the costs of these services are adjusted to reflect what Enbridge needs, not merely what EI does. (This is also related to the Service Schedule issue discussed below.)

10.3.3 The Board is concerned with the Company's testimony that a demand-pull approach is problematic because the Company does not necessarily know what is involved in providing a service. Enbridge might not know the details of how a service is provided, but it should know what services it needs. The Board also notes the testimony of senior staff which demonstrated limited familiarity with the corporate services and the costs allocated.

10.3.4 The changes to the service schedules and cost allocations made by Enbridge are very limited. Mr. Mees testified that he would question the value of Deloitte's engagement if too many changes to the service schedules or costs had to be made. This implies reliance on Deloitte for rigorous evaluation during the implementation process, but there is little evidence of this evaluation having been done. The focus in the process was on what EI does, not what Enbridge requires and what costs ratepayers should bear.

10.3.5 The Board notes that no party disputed that a service-based approach is an appropriate model for a corporate cost allocation exercise and finds that the drawbacks of an EI-led approach can be overcome. The evidence supports the conclusion that the RCAM methodology meets many of the recommendations of the 2004 CAM report. If implemented properly, this methodology requires Enbridge to turn its mind to the specific services it needs and provides evidence on the appropriateness of the amounts allocated which can be tested. The Board finds that Enbridge should continue to apply the RCAM, subject to the modifications and revisions identified below.

10.4 HAS THE RCAM BEEN APPROPRIATELY APPLIED?

10.4.1 Under this issue, the Board will address five areas:

- Service schedules
- Time estimates
- Time allocations
- Independent evaluation

- Intervenor involvement

10.4.2 In each of these areas, concerns were raised regarding possible shortcomings in the application or implementation of the methodology. It is the Board's conclusion that refinements can and should be made. We will address each area in turn.

10.5 BOARD FINDINGS

Service Schedules

10.5.1 There was some confusion in the hearing respecting the exact nature of the signed Service Schedules. In particular, it was not clear whether Enbridge is paying for all of the activities identified on the signed Service Schedules or only for those services it actually requires. There appears to be a gap in the overall documentation between the Primary Services, which are the descriptions of EI activities and which form the basis of the time study, the Service Schedules, and the actual services Enbridge requires and for which costs ought to be allocated.

10.5.2 There was testimony to the effect that there was much discussion and negotiation between EI, Deloitte and Enbridge about the definitions of services in the schedules, which suggests the Service Schedules are the more narrowly defined Enbridge-required services. However, the description of the time study, and its 2-stage review, suggests that there is a difference between the Primary Services and the Enbridge-specific allocations: first, the Primary Services are allocated across the three "buckets" (Enbridge, Other Affiliates, and All Affiliates); second, the Enbridge service recipients reviewed the results and made adjustments for services which were not required or where there was no agreement to purchase the "indivisible" portion.

10.5.3 The evidence does not support a conclusion that this second stage review was rigorous in all cases. Testimony by Enbridge witnesses indicated that service recipients got the Service Schedule and some time study information, although in many cases very little information was provided and there was no evidence of detailed or rigorous scrutiny by Enbridge. VECC submitted that Enbridge's validation of the Service Schedules was biased because Enbridge staff report to senior EI managers and the schedules were already completed.

10.5.4 The Board concludes that as long as the methodology is EI-led, then it is appropriate to have the Primary Services defined as those services which EI undertakes, because this approach enables the EI time study. However, the difference between the Primary Services and the Enbridge level of required services for ratemaking purposes should be better documented. For example, each Service Schedule should be refined to identify what subset of the Primary Service is allocable to Enbridge's ratepayers because the services are genuinely needed by Enbridge. Alternatively, the aspects of the Primary Service or related Support Services are not required by Enbridge, and hence not allocable to ratepayers, should be identified.

10.5.5 It would also be helpful to have a clear identification of which activities are in Enbridge's view:

- associated with "minding the investment"
- primarily to the benefit of EI
- related to standardization or coordination across the enterprise

10.5.6 This would assist in reviewing the components to determine whether they should be recoverable from ratepayers. It would also be helpful to have departmental cost allocations included in the Service Schedules. For example, it would be useful to see the total loaded departmental cost, the amount allocated to the Primary Service, and the amount allocated to Enbridge on a single page. Refinements such as these would make the methodology more transparent and more traceable.

Time Estimates

10.5.7 The time study was based on a one-time 12 month historical time estimate. In the study, respondents were asked to allocate their time for specific services across three "buckets": Enbridge, Other Affiliates, and All Affiliates. Mr. Johnson, the intervenors' witness, took the position that an annual historical time estimate was insufficient.

10.5.8 VECC noted that the Deloitte engagement letter and 2004 CAM report both recommended documented time tracking, not time estimation, and yet only time estimation was used. VECC submitted that this adversely affects the reliability of the results. Enbridge responded that the detailed time estimates meet the recommendation of the 2004 report and that there is no evidence to demonstrate that docketing would be more accurate.

10.5.9 The Board finds that more frequent time reporting is required to enhance accuracy. The evidence indicated that only half the respondents used work logs, time sheets or personal calendars to prepare their time estimates. This lack of rigour reduces the reliability of this measure. Enbridge's position that the benefits would not be significant from a more rigorous approach is not supported by any technical analysis; rather Enbridge's view seems to be more driven by expediency.

10.5.10 The Board finds that a more accurate form of time reporting should be used. However, if timesheets or dockets are not to be used, then the historical time study needs to take place at least quarterly.

10.5.11 Similarly, the Board finds that allocating time across three categories, identified as "Enbridge", "other Affiliates", and "All Affiliates" is deficient, because it places a significant emphasis on Enbridge. There is a risk that having a distinct Enbridge category will have the effect of inflating entries to that category. Deloitte itself recommended adding EI as an explicit bucket. While Enbridge submitted that adding an "EI bucket" would have no material effect, it did not object to it. The Board agrees that EI should be added as an explicit category, but also finds that adding 2 or 3 of the larger affiliates as distinct categories would be a significant and useful refinement, in that it would reduce the risk of disproportionate focus on Enbridge, particularly in a backward-looking time estimate study.

Time Allocations

10.5.12 VECC submitted that the results were inaccurate because the departmental cost data were not weighted by salary. Enbridge responded that the evidence showed that weighting the results would increase allocations.

10.5.13 The Board finds that it would be more accurate to use weighted average time allocations (on a fully allocated basis) to match the time allocations to the relevant salary levels.

Independent Evaluation

10.5.14 VECC and IGUA submitted that the Deloitte evaluative report was of no value because it was not independent. Similarly, Schools submitted that the evidence of Deloitte should be rejected, because it was not independent.

10.5.15 Enbridge responded that it chose Deloitte to evaluate RCAM because of its experience and noted that Deloitte did not claim to be independent. It asserted that because Deloitte's report is a criteria-based evaluation, it is informed and thorough. Enbridge submitted that Deloitte's evaluation was a natural extension of the knowledge and expertise it gained in developing the RCAM. In Enbridge's view, extra resources used on evaluation would not enhance the value to the Board.

10.5.16 The Board disagrees with Enbridge. An independent assessment is required, and while Deloitte was independent at the time of the CAM Report, once Deloitte was commissioned to create and implement the RCAM methodology, it was not in a position to review the application of the methodology independently. Both pieces of work by Deloitte were done on the same basis and by the same people. As part of the development and implementation of the methodology Deloitte was involved in assessing Enbridge's need for services, determining the appropriate allocators, and using the recommendations from the 2004 CAM Report. Substantially the same approach was then used to evaluate the results. Deloitte could review its own work, but it could not view it with "fresh eyes". As a result, the Board finds that the Deloitte evaluative report is of little value to the Board in determining the appropriateness of the corporate cost allocations.

10.5.17 The hearing of this issue was made more complicated by the lack of an independent review. The Board is now in a position where it must assess the results without the benefit of an independent evaluation.

10.5.18 The Board concludes that it would be preferable to use the RCAM to perform a straight allocation by (full) Primary Service to Enbridge and then have the independent evaluation make the necessary adjustments to the allocations for the assessment of need, scope, allocation, and cost/benefit. The Board would expect that an unadjusted RCAM would approximate the results of CAM because the objective of both is to allocate all of EI costs. However, these results then need to be adjusted for what Enbridge genuinely needs in the operation of the utility, and this can best be done through an independent evaluation. In other words, the Board recognizes that EI may well do the identified work, but not all of it is needed for Enbridge, and not all of the costs should be borne by ratepayers.

Intervenor Involvement

10.5.19 Enbridge chose Deloitte in part because it understood intervenor concerns from its earlier engagement. Indeed, the expectation of intervenor involvement was identified in the original Deloitte letter. However, there was limited intervenor knowledge of subsequent work and no substantive involvement in that work, including the evaluative report.

10.5.20 The Board finds that intervenors could have been involved in the development of the RCAM and at a minimum should have been involved in an independent evaluation. The fact that intervenors were not involved in the development and execution of an independent evaluation was a further shortcoming of this year’s overall RCAM study. The involvement of intervenors broadens the constituency beyond just the utility, thereby helping to ensure that the study is independent and that intervenor issues are addressed in the analysis. The Board directs Enbridge to include intervenors in the next independent evaluation.

10.6 DOES THE 2005 BOARD APPROVED AMOUNT FORM THE APPROPRIATE BASE FOR CONSIDERATION OF THE 2006 COST?

10.6.1 In 2005, the Board approved the Settlement Proposal which included $13.5 million for corporate cost allocation. IGUA submitted that the amount of $13.5 million should be the point of departure for the analysis of 2006 costs and that this understanding was unequivocally part of 2005 Settlement Proposal. Enbridge responded that it had not agreed to spend $13.5 million on corporate cost allocation or that the amount of $13.5 million should be used for comparison purposes in isolation of the facts surrounding its derivation.

10.7 BOARD FINDINGS

10.7.1 The Board finds that the amount agreed to in 2005 is relevant, because it was the result of an independent assessment of the reasonableness of the claimed costs, and in the Board's view shows the importance of a thorough independent evaluation. However, the Board finds that the 2005 amount is not determinative of the appropriate amount for 2006, nor is it the appropriate base for setting the 2006 amount, because the 2005 amount was developed without the benefit of a complete service-based methodology.

10.7.2 The Board is guided by all of the history on this issue, including the rapidly increasing amounts, the changes in methodology and the various external reports. The allowed amount for 2006 has been determined primarily through the application of the 3-prong test to the proposed amounts, but the adjustments are also set in recognition of the various shortcomings identified.

10.8 DO THE RESULTING COSTS PASS THE 3-PRONG TEST?

10.8.1 The 3-prong test was defined in the Board's Decision in EBRO 493/494 and can be summarized as follows:

1. Cost incurrence: Were the corporate centre charges prudently incurred by, or on behalf of, the companies for the provision of services required by Ontario ratepayers?

2. Cost allocation: Were the corporate centre charges allocated appropriately to the recipient companies based on the application of cost drivers/allocation factors supported by principles of cost causality?

3. Cost/Benefit: Did the benefits to the Company's Ontario ratepayers equal or exceed the costs?

10.8.2 The costs must pass all three tests. If a service, or the scope of service, is not needed by the gas distribution utility, then the cost should not be recovered from ratepayers. This is so even if the benefits may exceed the costs in question.

10.8.3 Deloitte, in its evaluation, made adjustments totalling $1.73 million in the areas of Business Development, Strategic Planning services, and aviation related expenses. In reviewing the claimed costs, the Board has examined the total costs, both direct and indivisible.

10.9 BOARD FINDINGS

<u>Test 1: Cost incurrence</u>

10.9.1 In the Board's view, costs will not pass this test if they relate to activities which:

- go beyond the scope of the service required for a utility,
- are associated with overall governance from a shareholder perspective or "minding the investment", or
- represent additional and superfluous management layers.

10.9.2 Costs will also not pass this test if they are unreasonable. Enbridge submitted that the EI costs are prudent because the allocated amounts meet the 3-prong test. Given that the Board cannot review the prudence of the EI budget, it is important to have a rigorous analysis of the stand-alone and in-house cost alternatives. This is addressed in the Cost/Benefit test below.

Scope of the service

10.9.3 There is a question respecting the extent to which some of the services are focused primarily on delivering benefits to the shareholder. The Board accepts that the interests of EI, as the shareholder, and Enbridge, as the subsidiary, are not mutually exclusive, but they are not always identical. Some services are designed for the interests of EI overall and not necessarily specifically for Enbridge and its ratepayers. Examples where interests are not necessarily aligned would include electric LDC activity, LNG and gas-fired power generation involvement, and upstream transportation initiatives. In cases such as these, the interests of EI go beyond the level of activity required by a regulated stand-alone utility, operating in a defined franchise territory.

"Minding the investment"

10.9.4 Activities related to "minding the investment" are included in the Service Schedules. The description of the process suggests that the costs associated with "minding the investment" are included in the indivisible portion, which is in part allocated to Enbridge. The Board has in the past found that this type of cost is appropriately to the account of the shareholder and should not be borne by Enbridge ratepayers. The Board continues to hold that view.

Additional management

10.9.5 It is not clear to the Board why ratepayers should pay for the contributions of EI executives who are superior to the senior management of Enbridge. If their contributions are strategic in nature, then the benefits flow most directly to EI. If their contributions are related to governance, then it is governance from the shareholder's perspective and therefore more in the nature of "minding the investment". If their contributions are advisory, the Board is of the view that the costs are to some extent beyond what is required for a core distribution utility, given the associated expense and the scope of activity.

Test 1 - Conclusion

10.9.6 VECC made submissions on a number of specific services. These can be summarized as follows:

- Customer, Industry and Community Relations includes functions described for the Group VP Corporate Services that are of no benefit to a stand-alone unbundled gas distributor. The activities related to expanding business and furthering the interests of the entire EI enterprise provides for no separation of EI's interests and Enbridge's interests. The services largely would not be required by a stand-alone gas utility.

- Gas Supply, Storage and Transportation includes activities which are not appropriately allocated to ratepayers.

- For Investor Services and Capital Market Financing and Access, the cost of raising equity is already compensated for through the allowed return on equity.

- The Board of Directors costs are related to EI's management of its investment in Enbridge and provide for the assurance of consistency amongst subsidiaries. Enbridge already has a CEO which performs these functions. A stand-alone entity would not require that its own CEO be assisted by another CEO, CFO, etc. to provide assistance to the Board of Directors.

- Internal Employee Communication includes the cost of integrating Enbridge within the EI Enterprise. Enbridge already has an O&M budget for employee communications.

10.9.7 Enbridge disagreed with VECC's analysis and submitted that each of the services is needed and that Enbridge would incur related expenses on a stand-alone basis.

10.9.8 The Board concludes that the evidence shows that each of the following services includes costs which do not pass this first test:

- Capital Market Financing and Access: The allowed return on equity for Enbridge already includes a floatation allowance which is related to some of the activities. Some activities are related to overall governance or co-ordination of the corporate family.

- Board of Directors Support: Many of the activities are related to minding the investment and to enterprise co-ordination/governance.

- Business Development: A number of the activities go beyond the needs of a core distribution utility, and in many respects the activities represent an additional layer of senior management. The Deloitte adjustment, which removed most of the indivisible costs, is not sufficient.

- Customer, Industry & Community Relations: Some of the activities are related to Enbridge, but go beyond the scope necessary for a distribution utility (for example, the CEO of EI responding to Enbridge related customer complaints). Other activities are driven by the broader EI strategy of which Enbridge may be a part, but the benefits are not related to Enbridge independent of other corporate considerations. An example would be the extensive activities related to the Alaska pipeline.

- External Communications: The focus is on the EI brand and related objectives, which is beyond that needed by Enbridge. For example, Enbridge does not need nationwide and international advertising.

- Gas Supply, Storage and Transportation Strategy: The description of this service is related more to EI business development. In other respects, the activities indicate additional layers of senior management, which are either redundant or beyond the scope required for Enbridge.

- Government Relations: The references to the regulatory environment for an Alaska gas pipeline indicate that activities in this area are beyond the scope necessary for Enbridge.

- Internal Employee Communications: This is partly related to minding the investment, and other activities would not be needed by a stand-alone utility because they are related to integrating Enbridge into the EI enterprise.

- Strategic Planning: This area includes activities which appear to duplicate Enbridge efforts or are beyond the scope required by Enbridge in that they are focused on the enterprise wide strategy or are related to EI's position as owner of Enbridge. The Deloitte adjustment is this area is not sufficient.

10.9.9 The Board finds that the allocation for each of these services should be reduced by 50%. In the absence of a rigorous independent evaluation, the Board must make adjustments on the basis of the evidence available, and the evidence supports a conclusion that on balance at least half of the activities included in these services do not meet the first test. The total cost allocation for these services is $5.3 million. A reduction of 50% results in a disallowance of $2.7 million.

<u>Test 2: Cost allocation (appropriateness of allocators)</u>

10.9.10 The RCAM allocates costs using a number of allocators. These include:

- Direct allocations (insurance, compensations, etc.)

- Time based allocations

- Volumetric allocations

- Allocators designed to capture complexity

10.9.11 The last two approaches are used to allocate the costs related to the "All Affiliates" category in the time study, which are considered "indivisible" costs.

10.9.12 VECC submitted that the use of indivisible time made it impossible to validate the results of the methodology. VECC concluded that the indivisible costs are allocated using proxies which have no foundation in cost causality. In VECC's view, these are residual costs that are not incurred directly for services required by Enbridge and therefore fail the first of the three-prong test. VECC concluded that the support for EI's costs should be a pure time-based methodology founded on time docketing with true-up provisions

10.9.13 Enbridge responded that it was necessary to examine need first, then the allocator. VECC argued that they are not incurred directly and therefore fail the 1st test. Enbridge maintained that these are not residual costs, but rather are services which benefit all EI affiliates.

10.9.14 The Board finds that time is the most appropriate allocator, but when time cannot be allocated to specific affiliates, then it is appropriate to use other allocators. Mr. Johnson, appearing on behalf of intervenors, criticized the large amount of "indivisible" costs and maintained that there should be some way to allocate that associated time to specific affiliates. He seemed to expect EI departments to be able to allocate costs as if they were stand-alone businesses, and he compared the indivisible costs to overhead. The Board finds that this is an unrealistic expectation and agrees with Enbridge that EI departments are undertaking activities for EI as a whole, not for separate clients. That does not mean these costs are overhead.

10.9.15 The Board finds that the use of non-time allocators may be reasonable, but notes that if the time study is conducted appropriately (as reflected in the findings above), then it is likely that there will be less indivisible time. The Board sees it as one of the roles of the independent evaluator to assess the allocator subsequently applied to any residual indivisible time.

10.9.16 The Board will make no specific adjustments for this test. Adjustments made for the other tests are applied to both the direct and "indivisible" costs.

Test 3: Cost/Benefit

10.9.17 In order to pass this test, Enbridge must demonstrate that the allocated costs for a service are less than what Enbridge would incur as a stand-alone gas distribution utility. The Board also expects that there will be demonstrable scale economy benefits. In other words, in some areas, the corporate cost allocation should result in costs that are lower than the stand-alone equivalent. The Board recognizes that EI would have to incur a certain amount of oversight and coordination costs to be able to derive scale economies. It would be appropriate to allocate this type of cost to Enbridge, even though they would not be incurred by a stand-alone gas distribution utility, provided that there are demonstrable scale economy benefits and the total cost is lower than the stand-alone equivalent.

10.9.18 Mr. Johnson agreed that scale economies can occur with corporate cost sharing and that they are desirable, but he observed that there was not much evidence of them in this case.

10.9.19 In the Board's view, this cost/benefit analysis is an area where the independent evaluation is particularly important and an area where the Deloitte evaluative report is deficient. The evidence of the cost/benefit analysis is cursory at best, and the evaluative report demonstrates that this analysis was often judgemental and based on anecdotal evidence rather than a structured review. This analysis is particularly important because the Board has no means of determining the prudence of EI costs and because of the magnitude of the costs in question.

10.9.20 The Board finds it is appropriate to make an adjustment to the allocations of all service categories because Enbridge has not ensured that the cost/benefit analysis has been completed with sufficient rigour. The Board adjustment will be 15% to each of the categories which has not otherwise been adjusted. The adjustments made for Test 1 (50% reductions as described above) and for scale economies (discussed below) are sufficient to incorporate this finding and will not be increased. The total cost allocation for the associated services is $4.3 million, and a 15% reduction results in a disallowance of $650,000.

10.9.21 There are two areas in which the Board would particularly expect to see evidence of scale economies: IT and HR. Amongst the IT-related services, the Deloitte evaluative report provides no evidence of scale economies for Enterprise IT Program Management and only limited evidence of such benefits for Enterprise IT Strategy Planning and Management. With respect to the EFS systems (Oracle, Khalix and Necho) the Deloitte evaluation indicates that the total charges are reasonable, but there is no evidence of scale benefits.

10.9.22 Amongst the HR-related services, the Deloitte evaluative report provides no evidence of scale economies for HRIS Management & Technical Support, Employee Development, or Total Compensation and Benefits. There is some indication of scale benefits for HR Advice, Labour Relations Strategy and Union Labour Relations Strategy, and these will not be adjusted.

10.9.23 The Board finds that it is appropriate to adjust the allocations for these services (other than the exceptions in HR) by 25% in order to impute a reasonable level of scale economy benefits. The total cost allocation for these services is $3.3 million, and a reduction of 25% results in a disallowance of $825,000.

Conclusion

10.9.24 VECC concluded that Enbridge has not justified the amount it has requested as just and reasonable because the claimed costs do not reflect the level for required services. In its view, any amount over the 2005 level of $13.5 million, adjusted for inflation (or a total of $14.3 million), should be disallowed. The Council supported VECC and agreed that the allowed amount should be no more than $14.3 million. Schools also adopted VECC's submissions and concluded that the Board should allow $13.5 million plus 2% for inflation. IGUA supported the submissions of VECC, the Council and Schools and recommended that no more than $14.3 million be allowed.

10.9.25 Enbridge responded that intervenors do not dispute that EI in fact spends at least $21.3 million to provide services to Enbridge, but their thrust is that ratepayers should not pay the full cost. In Enbridge's view this is not just and reasonable.

10.9.26 The Board does not agree. EI may spend $21.3 million to provide services to Enbridge, but that does not mean these services are truly required by Enbridge or that they should be paid for in full by ratepayers. It is not just and reasonable to require ratepayers to pay for unnecessary or excessive services, even if these may create some benefits. The Board finds that adjustments are warranted and it has made these adjustments in the context of the 3-prong test. No adjustments have been made to any of the direct charges or to the return on invested capital. The resulting total disallowance is $4.1 million, and the allowed amount is $17.2 million.

10.9.27 The Board finds that Enbridge should continue with the RCAM methodology as amended with the refinements identified above. Included in those refinements is the particularly critical independent evaluation. The reasonable cost of that evaluation should be borne by ratepayers, and a deferral account for that purpose is approved later in this decision.

10.9.28 The Board further finds that in evaluating each service, the independent review should consider whether:

- the service is specifically required by the utility;
- the level of service provided is required by the utility;
- the costs are allocated based on cost causality and cost drivers;
- the cost to provide the service internally would be higher and the cost to acquire the service externally on a stand-alone basis would be higher; and,
- there are scale economies.

10.9.29 A summary table of the corporate services and the Board adjustments, which have been discussed in detail above, appears below.

Enbridge Corporate Cost Allocation – 2006

Service	EGDI Proposed Allocation $	Board Adjustment %	Board Allowed Allocation $
Audit & Accounting Advice	96,125	15%	81,706
Board of Directors Support	665,203	50%	332,602
Business Development	1,167,380	50%	583,690
Capital Market Financing & Access	1,157,243	50%	578,622
Cash Management & Banking	298,671	15%	253,870
Planning System Technical Support	313,323	25%	234,992
Corporate Compliance	170,342	15%	144,791
Customer, Industry & Community Relations	670,640	50%	335,320
Emerging Energy Technology Research	120,411	15%	102,349
Employee Development	326,911	15%	277,874
Enterprise IT Program Management.	190,359	25%	142,769
Enterprise IT Strategy, Planning & Management	833,389	25%	625,042
Expense System Management & Technical Support	179,422	25%	134,567
External Audit Coordination	95,666	15%	81,316
External Communications	118,895	50%	59,448
Financial & Project Accounting System Technical Support (Oracle)	310,374	25%	232,781
Gas Supply Storage & Transportation Strategy	645,305	50%	322,653
Government Relations	349,137	50%	174,569
HRIS Management & Technical Support	533,506	25%	400,130
HR Advice	122,859	0%	122,859

Insurance Claims Support	5,913	15%	5,026
Insurance Strategy & Management	107,428	15%	91,314
Internal Employee Communications	138,425	50%	69,213
Investor Services	1,645,234	15%	1,398,449
Labour Relations Strategy	92,231	0%	92,231
Legal Advice	188,357	15%	160,103
Planning, Management & Execution of Internal Audits	213,460	15%	181,441
Rate Regulated Entity Support	267,589	15%	227,451
Records & Information Management	182,416	15%	155,054
Risk Assessment & Management	584,140	15%	496,519
Strategic Planning	432,882	50%	216,441
Supply Chain Management	11,832	15%	10,057
Tax advice	6,325	15%	5,376
Tax Reporting & Planning	8,013	15%	6,811
Total Compensation & Benefits	936,661	25%	702,496
Union Labour Relations Strategy	121,890	0%	121,890
Subtotal	**13,307,957**		**9,161,819**
Direct EFS Charge	(405,139)	--	(405,139)
Directors' Fees & Expenses	492,346	--	492,346
Risk Management System	113,721	--	113,721
Insurance Premiums	4,905,000	--	4,905,000
Audit Fees	778,650	--	778,650
EGD Stock Based Compensation	1,873,200	--	1,873,200
Subtotal	**7,757,778**		**7,757,778**
Return on Invested Capital	**248,327**	--	**248,327**
TOTAL	**21,314,062**		**17,167,924**

10.10 SHOULD THE BOARD BE CONCERNED THAT ACTUAL PAYMENTS TO EI WILL BE IN ACCORDANCE WITH CAM – NOT RCAM?

10.10.1 It was clear from the evidence that regardless of the results of the RCAM, the payment for corporate services from Enbridge to EI will continue to be governed by CAM. Schools expressed concern regarding the payment of the CAM amount, and recommended the use of an Excess Earnings Variance Account to capture payments from overearnings.

10.10.2 Enbridge responded that it intended to honour its contracts, that it had a legal contract and that it needed the services governed by the contract. Enbridge submitted that the development of RCAM did not invalidate CAM. It asserted that RCAM was developed in recognition of the need to tailor the methodology to meet the needs of the Board. Enbridge maintained that it was practical to use CAM because of other subsidiaries within the EI Group.

10.11 BOARD FINDINGS

10.11.1 The Board is concerned that CAM will govern actual payments. The Board notes the testimony of both Enbridge and EI witnesses to the effect that the RCAM is more rigorous than CAM. As a result, the Board believes that the continued operation of CAM suggests that Enbridge and EI’s commitment to the RCAM methodology will be tempered. There is also the potential for an adverse financial impact on Enbridge if it finds it must make budget reductions elsewhere to make “scorecard” targets and payments to EI in accordance with CAM. The Board will not establish the variance account proposed by Schools, but this is an area that is of interest to the Board and one which the Board will monitor going forward.

11. OTHER O&M EXPENSES

(O&M excluding DSM, Corporate Cost Allocation and Customer Support)

11.1 BACKGROUND

11.1.1 Enbridge submitted that the full amount of the overall O&M budget is required to continue to provide an acceptable quality of service to existing and new customers, increase throughput and maintain the distribution system. Enbridge explained that the increase from 2005 to 2006 is attributable to inflationary cost pressures, the high level of customer additions, regulatory and legislative requirements, new programs and changes in the marketplace. Enbridge stated that it continues to look for ways to increase savings through improved productivity.

11.1.2 The Board addresses the budgets for corporate cost allocation and customer support in separate chapters of this Decision. A Partial Decision with Reasons was issued respecting DSM issues. This section therefore deals with the balance of the O&M budget, which for purposes of this Decision will be called "Other O&M".

11.1.3 Enbridge proposed a 2006 budget for Other O&M of $185.5 million, which represents a 13.8% increase over the Board-approved 2005 settlement of $162.9 million.

11.1.4 The Board has identified three issues in respect of Other O&M:

- What is the appropriate level of the total Other O&M budget?
- Should adjustments or specific findings be made on the individual departmental budgets?
- Should Enbridge be directed to file specific evidence with respect to the Natural Gas for Vehicles (NGV) program?

11.2 WHAT IS THE APPROPRIATE LEVEL OF THE TOTAL OTHER O&M BUDGET?

11.2.1 A number of parties submitted that the level of the budget increase was motivated by Enbridge's expectations regarding incentive regulation. Enbridge denied these accusations. The Board does not believe it is necessary for purposes of this issue to inquire into the motivations of Enbridge in preparing the O&M budget. The Board is focused on the reasonableness of the budget itself and considers that the motivations in and of themselves are not determinative of reasonableness.

11.2.2 Many intervenors submitted that the total budget for Other O&M was excessive and should be reduced to $172 million. In the Council's view, a 5% increase over the 2005 Board-approved level would be sufficient to take account of inflation, customer growth, cost pressures and productivity. Most other intervenors took the same approach.

11.2.3 Enbridge responded that the intervenors' proposed 5% index was unreasonable and unsupported by evidence. Enbridge proposed an alternative "PBR" style index, which would result in a budget for 2006 of $185.7 million:

- The starting point should be $166.2 million, which is the 2005 estimate, not $162.9 million, which is the Board-approved level.
- Accounting for customer growth and inflation over 15 months would add 6.78% to the cost level. A productivity factor would reduce costs by 1.38%.
- Uncontrollable increases of $8.5 million should be allowed for benefits, insurance, compliance, meter inspection, and OEB costs.

11.3 BOARD FINDINGS

11.3.1 The Board agrees that it must consider the total O&M budget and whether it is reasonable. However, Enbridge submitted that to compare a global O&M total to the previous year's settled amount without looking behind the global number is unfair and unreasonable, and the Board agrees. The Board is not convinced that applying an index to the total level of the Other O&M budget adequately accounts for the customer growth which Enbridge has experienced.

11.3.2 In terms of a global approach, Enbridge submitted that it is appropriate to look at its O&M cost per customer, a measure utilized by the Company and the Board to review cost levels and trends over time. Enbridge noted that over the past four years the increase in this measure is only marginal, and that a recent American Gas Association ("AGA") study shows that Enbridge had the lowest distribution O&M cost per customer amongst a group of almost 70 gas utilities.

11.3.3 Energy Probe submitted that Enbridge's operating efficiency is declining because the cost per customer should be declining but is not. Energy Probe noted that costly capital expenditures had been proposed on the basis of technical improvements and scale economy benefits, but that if the application is granted, the result will be the largest rate increase in 10 years. In Energy Probe's view that would not be reasonable or realistic.

11.3.4 The Board agrees that Enbridge's level of cost per customer does not support a conclusion that the overall O&M level is reasonable. The Board would expect to see evidence of scale economies in the cost per customer data, particularly in light of the fact that Enbridge's customer base has expanded by 40% in 10 years. If such economies are not being created, the Board would expect to see a compelling analysis of why that is so.

11.3.5 More importantly, this measure is most relevant when it can be compared to that of other companies, in other words in the context of benchmarking. In that respect, the data from the AGA are not helpful in that Enbridge itself concluded there was limited value in the study (at least in respect of customer care costs) given its mechanistic development and the lack of any analysis or review. To the extent that the AGA report is valid, the data suggest a variety of performance levels for Enbridge in the various cost categories.

11.3.6 The only other comparison that was made was with Union Gas. IGUA submitted that the evidence shows that Enbridge is not controlling its costs as effectively as Union. The Board accepts that this comparison may have limitations, given the differences between Union and Enbridge, but again, to the extent it is relevant, it does not support a conclusion that Enbridge's costs are reasonable.

11.3.7 In the absence of reliable benchmarking data from comparable companies, the Board is left with considering some sort of indexing based on inflation and customer additions, both of which can be observed objectively. The Board must also consider productivity changes and cost pressures, although these factors are more difficult to observe objectively.

11.3.8 The Council submitted that the size of the increase sought after years of successful operation should cause the Board to be sceptical and that claims of unusual cost pressures were not supported by the evidence. The Council noted that one of Enbridge's key claims was related to the pressures of customer additions, but submitted that not all categories of expense are directly influenced by the level of customer additions.

11.3.9 Enbridge replied that the cost pressures were not due to 2006 being an extraordinary year, but rather were the result of cost pressures that have built up over 10 years of customer additions of approximately 50,000 per year. Enbridge also identified a number of costs beyond its control, namely insurance, benefits, compliance costs and OEB costs.

11.3.10 VECC submitted that the focus of the budget documentation was on increasing the budget from the 2005 ADR settlement level, rather than on cost reductions, and that nearly all departments show large increases which are unreasonable and excessive. Rather than focusing on micromanaging Enbridge, in VECC's view the Board should instruct Enbridge to prioritize its budget and operate within a reasonable total level compared to previous years. Enbridge responded that it does seek cost reductions and identified reductions related to audit fees, IT, telecommunications, internal counsel, and electronic filing as evidence of these reductions.

11.3.11 The Board finds that the evidence does not support Enbridge's claim regarding the cost pressures arising from 10 years of cumulative customer additions. There may be pressure on costs to increase, but there should also be substantial scale economy benefits, and the cost per customer data does not demonstrate these are being achieved in

2006. The Board does accept the evidence regarding some of the uncontrollable costs, namely insurance, benefits, meter inspection and Board costs. However, Enbridge should be demonstrating that it is generating offsetting savings in other areas. The evidence did indicate some costs savings.

11.3.12 The Board agrees with the intervenors that applying an index amount to Other O&M expenses is a reasonable approach. However, the Board believes it is best developed using the cost per customer measure. The Board acknowledges that applying an index to the total O&M does not reflect the impact of the growing customer base; applying an index to the cost per customer does. In this regard, the Board finds that the cost per customer should not exceed the nominal cost per customer in 2005.

11.3.13 The relevant figure for 2005 is one which incorporates the Board approved level of customer support costs and corporate cost allocation, and the 2005 estimate of the remaining O&M expenses. This calculation results in a nominal cost per customer of $165.55 for 2005. The Table below shows the derivation of this amount.

Derivation of Board adjusted Cost per Customer for 2005

"Other" O&M (2005 Estimate)	$166.2 million
Add: Customer Support (2005 Board Approved)	$110.1 million
Add: Corporate Cost Allocation (2005 Board Approved)	$13.5 million
O&M (excluding DSM)	$289.8 million
Less: NGV Ancillary Program – 2005 Board Approved	$0.9 million
Total O&M (Excluding DSM & NGV)	**$288.9 million**
Number of Customers (2005 Estimate)	**1.745 million**
Adjusted Cost per Customer 2005	**$165.55**

11.3.14 The nominal cost per customer for 2006 should not exceed this level. The Board acknowledges the upward pressure of inflation and uncontrollable expenses, but finds that productivity improvements and scale economies from customer additions should be sufficient to offset the upward pressure. This cost per customer figure results in a total 2006 O&M budget (excluding DSM & NGV Ancillary Program Cost) of $296.8 million. Given the allowed amounts for customer support and corporate cost allocation (as discussed in Chapters 7 and 8) and the NGV budget of $1 million, the resulting "Other O&M" totals $176.5 million. The derivation of this amount appears in the Table below.

Derivation of 2006 O&M
(excluding DSM, Customer Support, Corporate Cost Allocation)

Cost per Customer	**$165.55**
Number of Customers	**1.793 million**
Total O&M (excluding DSM & Ancillary)	**$296.8 million**
Less: Customer Support	$104.1 million
Less: Corporate Cost Allocation	$17.2 million
O&M (Excluding DSM, NGV Ancillary Program, Customer Support, Corporate Cost Allocation)	$175.5 million
Add: NGV Ancillary Program	$1 million
Total "Other O&M"	**$176.5 million**
Disallowance from proposed ($185.5 million)	**$9 million**

11.3.15 The Board expects that productivity improvements, or budget prioritization, will allow Enbridge to manage the cost pressures within this envelope. We note that the level of Other O&M at $176.5 million is 8.3% higher than the 2005 Board approved level and is 6.2% higher than the 2005 estimate.

11.3.16 Schools proposed that if there are overearnings in the Test Year, and the Company pays disallowed amounts to affiliates, then subject to further evidence from the Company, the lesser of the excess payments and the overearnings should be refunded to the ratepayers. In Schools' view, this is justified because the overearning would be the result of the budget being set too high, despite the disallowances.

11.3.17 Enbridge responded that under this proposal it would in effect have to pay costs twice which were not included in rates. Enbridge submitted that the proposal amounted to an alternative regulatory model to the forward test year approach.

11.3.18 The Board believes that the concerns expressed by Schools and the objective of Schools' proposal have merit. However, the Board finds that these issues are more appropriately addressed in the context of setting the multi-year incentive rate regime and therefore the proposed deferral account will not be implemented for 2006.

11.4 SHOULD ADJUSTMENTS OR SPECIFIC FINDINGS BE MADE ON THE INDIVIDUAL DEPARTMENTAL BUDGETS?

11.4.1 The Board must also consider whether it should either make specific findings on individual departmental budgets, allocating the total amount of Other O&M to particular departments, or rather create a global envelope, which does not differentiate between specific department budgets.

11.4.2 The Council's recommendation for a total level of Other O&M was accompanied by discussion and analysis of some of the individual departmental budgets. In its view, the budget increases for Finance, Engineering, Opportunity Development, Regional Operations, Legal Regulatory and Public Affairs, and Information Technology were not supported with sufficient evidence.

11.4.3 Schools submitted that Enbridge should be managing costs within a reasonable total. It also submitted that the Board should determine an allocation of the total O&M budget to the individual departments, although it concluded that Enbridge should be expected to operate within the total and not to the specific allocated amount. Schools identified the detailed specific adjustments, totalling approximately $16.1 million in the following departments: Finance, Engineering, Opportunity Development, Regional Operations, Human Resources, Legal, Regulatory, Public Affairs, and Non-Departmental O&M.

11.4.4 Enbridge responded that the Board must look at individual budgets to appreciate the specific factors that influence the overall budget level and submitted that intervenor arguments, and in particular Schools' proposed adjustments, were largely unconnected to the detailed departmental evidence.

11.5 BOARD FINDINGS

11.5.1 The Board recognizes that parties made significant efforts throughout the proceeding to examine the details of individual department budgets. In the Board's view, this examination was hampered somewhat by the inconsistencies in Enbridge's approach to the presentation of the evidence and the associated variance analyses. The Board therefore agrees with the intent of Schools' submissions recommending specific filing requirements for next year and notes that the Board has now issued Minimum Filing Requirements for purposes of the 2007 filings.

11.5.2 Despite its limitations, the examination was useful, in the Board's view, to test Enbridge's claims regarding the cost pressures facing the Company. In this regard, the Board concludes that for the most part, Enbridge's claims of unusual cost pressures arising from years of high customer additions are not borne out by the evidence of many individual departments. Further, the evidence shows that to the extent that there may be unusual cost increases in some areas, Enbridge has not made significant efforts to find offsetting decreases in other areas.

11.5.3 The Board will not make specific findings regarding individual departmental budgets. The Board notes that Schools, which provided the most detailed submissions in this regard, acknowledged that Enbridge should operate within the total and not to the allocated amounts. The Board agrees that it is appropriately the responsibility of Enbridge to manage the utility's budget in the way that it determines best achieves its objectives and discharges its obligations to customers.

11.6 SHOULD ENBRIDGE BE DIRECTED TO FILE SPECIFIC EVIDENCE WITH RESPECT TO THE NATURAL GAS FOR VEHICLES (NGV) PROGRAM?

11.6.1 The Settlement Proposal approved by the Board in this proceeding depicts Issue 10.1 as being a "partial settlement". All of the participating parties, except Schools, agreed that revenues of $600,000 should be imputed to the NGV program.

11.6.2 In its final submissions, Schools in effect accepted the proposed settlement regarding the imputation of revenue, but further argued that the Board should direct Enbridge to file a comprehensive multi-year program in its next rates case showing:

- the steps Enbridge will take over the life of the incentive ratemaking period to put the NGV program on a profitable footing, and then to drive positive net benefits to the ratepayers from the NGV initiative, and

- the recovery over the incentive ratemaking period of imputed revenues borne by the shareholder since 1995, including interest, or such amount of those imputed revenues as can be recovered once the program is more profitable.

11.6.3 Enbridge responded that Schools' proposal should be dismissed because: it was not the subject of an open discussion amongst the parties; the program is not subsidized by ratepayers; there is no evidence demonstrating that the underlying economics have fundamentally changed; and, the evidentiary record on this issue was not tested.

11.7 BOARD FINDINGS

11.7.1 Schools has in effect argued for a broad based inquiry into the NGV program. The Board notes that in any given year, Enbridge's programs are reviewed in light of current and expected events, and the Board expects that the NGV program will be examined in that context in Enbridge's next rates proceeding. The Board does not believe that the evidence in this proceeding supports a finding that there should be a fundamental change in the regulatory approach to this program and therefore the Board will not direct Enbridge to produce the evidence proposed by Schools. However, Schools will be able to pursue the issues it has raised, if it so chooses, through the next rates proceeding.

12. TIMING AND CHANGES TO THE 300 SERIES OF RATES

12.1 BACKGROUND

12.1.1 The 300 series of rates provide for unbundled services where a customer can elect to receive services such as distribution or storage. The Company has had unbundled rates for distribution, load balancing and storage service since 1988. Rates 300 and 305 provide distribution service or point-to-point transportation from Enbridge's city gate to the customer's terminal location, assuming that a customer is able to forecast its consumption on a daily basis and deliver the exact amount of gas required. Under Rate 310, which is a load balancing service, Enbridge undertakes to match actual consumption and confirmed gas deliveries, on behalf of the customer, within a predefined tolerance. Under Rate 315 storage service, the customer receives a notional allocation of storage that it is required to manage by nominating withdrawals and injections based on its daily consumption and gas deliveries to the city gate. Enbridge also provides bundled services.

12.1.2 In the mid 1990's unbundled customers migrated to bundled service. No customers have taken service on the 300 series rates since then, with the exception of a landfill gas application that currently uses unbundled distribution rates. Enbridge stated that the reason that these rates ceased to be attractive is based on the fact that the bundled rates for large volume customers reflected a lower cost for long haul transportation than customers would pay if they made their own arrangements for transport on TCPL as unbundled customers. The result was that small volume customers paid more. In addition, these bundled rates allowed customers to make their own arrangements for transport, but compensated them for the full toll paid to TCPL, as a T-service credit, and replaced it with a transport cost that was less than full toll.

12.1.3 Enbridge is currently involved in a process to address these cost allocation issues, with the objective that the 300 series rates may again become attractive. In 2005, the

Company agreed to a cost allocation change that will result in two outcomes: (i) over the next four years the Company will increase the transport cost for large volume customers to reflect the average transport costs in bundled rates paid by the Company; and (ii) at the end of four years the Company will cease to compensate customers who make their own transport arrangements. These upstream cost allocation changes will be fully phased in by October 2007.

12.1.4 In the 2005 Settlement Proposal Enbridge agreed that for the next rates case it would consider changes to all aspects of its 300, 305, 310 and 315 rates schedules including consideration of the following matters:

- combined multi-facility delivery, storage and load balancing options
- flexibility in delivery point, minimum annual volumes, daily delivery obligations, provision of fuel, and choice between bundled and unbundled services
- term differentiated rates

12.1.5 Enbridge stated that it has taken steps to implement the commitment in the 2005 Settlement Proposal, but that it was unable to bring forward a new rates proposal for 2006. The Company stated that the difficulty in bringing forward a new proposal was chiefly related to timing and the need for additional information about the needs of customers and potential customers. Enbridge submitted that it will be in a position to file a proposal for redesigned distribution and load-balancing services as part of its 2007 rates case.

12.2 BOARD FINDINGS

12.2.1 Intervenors suggested that Enbridge has reneged on the settlement agreement insofar as it has deferred consideration of these rate classes and issues related to them pending the outcome of the Natural Gas Forum. Intervenors representing large commercial, industrial and institutional customers suggested that their agreement to the settlement in the previous case was contingent on Enbridge coming back this year with concrete proposals for changes to the Rate 300 series. Enbridge asserted that it will present Rate 300 changes after the Natural Gas Forum and the Natural Gas Electricity Interface Review have developed recommendations and more is known about the evolution of the gas-fired electricity generation market.

12.2.2 Intervenors are concerned that it now appears that the reasonable expectation is that the 300 rate series will not be redesigned before 2007, and for some elements, not until well beyond that date. This view is shared by TransAlta, OAPPA and IGUA. A further irritant for these customers is the fact that customers wishing to change rate classes sometimes have to wait for as much as one year or 10 months to make the transition to the new rate class.

12.2.3 Enbridge's reluctance to provide a complete revision of the 300 series of rates at this time is somewhat understandable. There are numerous uncertainties associated with the evolution of the gas market which the Natural Gas Forum is designed to address. The Company is concerned that if it acts now, before important issues respecting storage and the gas electricity interface are positively resolved, it may be sending inappropriate and unreliable signals to its customers with the result that those customers may make bundling/unbundling decisions in a rate environment that is not stable.

12.2.4 The Board considers that this may be a situation where the perfect is the enemy of the good. In deciding to wait until the uncertainties are positively resolved by proceedings pursuant to the Natural Gas Forum, the affected classes of customers, which comprise a large and important segment of Ontario's economy and infrastructure, are restricted to unreasonably limited service and rate options. Their acquiescence in the re-allocation of upstream costs, which led to the very significant increases they are now experiencing, entitles them to such relief as may be reasonable, as soon as reasonably possible.

12.2.5 Part of Enbridge's decision to delay the re-design of the 300 series of rates is a result of its decision to design the 300 series of rates so as to accommodate the merchant electricity generator group of customers, as well as conventional large commercial industrial and institutional users that have until recently formed the target group for these rates. Enbridge's consultant, retained as part of the Company's "consideration" of the

300 series of rates, appears to have been focused on the prospective merchant generator users. His recommendation to forestall reworking of the rates is directly attributable to his concerns about the outcome of the various NGF proceedings, as they impacted the prospective merchant generation users. In effect, the conventional customers are being asked to await developments related primarily to the prospective merchant generation group.

12.2.6 Without in any way wishing to predict or influence the outcome of the NGF proceedings, the Board considers that it may well be the case that the arrangements and rate structures necessary to accommodate the merchant generator group properly may need to be very specific to these customers (and customers with similar loads). This is especially so as it concerns storage. It is clear from the Company's evidence that one of the stumbling blocks in arriving at a rate redesign involved the storage requirements of the generation plant that is trying to respond to a short term electricity market opportunity. Load balancing facilities and procedures for such plants also present requirements not typically required or relevant for other large users.

12.2.7 It appears to the Board that Enbridge's attempts to arrive at a viable and responsive redesign of the 300 series of rates foundered in trying to accommodate what may be irreconcilable differences in the needs of respective groups of customers. In short, it may well be the case that conventional and merchant generation customers may not be appropriately combined under a single series of rates.

12.2.8 This aspect is particularly important, when it is considered that proper allocation of the costs attributed to the developing merchant generation sector is a critical element of government policy. The government has indicated that it is important that electricity customers understand and pay for the true cost of the provision of electricity. To the extent that an overly broad or inclusive rate class could result in inappropriate allocation of costs between members of the class this objective would be compromised.

12.2.9 The fact that there is another proceeding ongoing at the Board (NGEIR) that will address issues around rates and services with respect to gas delivery and the generation of electricity is fortuitous. As part of NGEIR, the Company is required to prepare and present a series of rates reflecting the anticipated needs of the merchant generation category of customers. Such needs have been referenced in this Decision, but a more complete discussion of the apparent special characteristics of the merchant generation class can be found in the documents issued in connection with the NGEIR process.

12.2.10 In the Board's view, NGEIR also provides the most appropriate opportunity for the Company to prepare and present redesigned rates for the conventional large volume customer. Accordingly, the Board directs the Company to prepare and file as part of its required filing in the NGEIR process a series of rates which reflects the perceived requirements of the conventional large volume customer seeking revised Rate 300 series rates. The Board urges the Company to consult with stakeholders to ensure that the rates filed reflect the anticipated services and standards applicable to this class of customer.

12.2.11 The Board will issue in due course consequential NGEIR Procedural Orders to reflect this finding.

12.2.12 The Board also directs Enbridge to develop a process whereby customers wishing to take up the re-designed rates can be transitioned to the new rate class within a more condensed time period than is now available.

13. GAS DISTRIBUTION ACCESS RULE

13.1 BACKGROUND

13.1.1 In the 2006 Settlement Proposal, the parties agreed that the disposition of the amounts recorded in the 2005 Gas Distribution Access Rule Variance Account should be deferred until the Board has provided guidance with respect to the allocation of GDAR costs. The parties also agreed to the establishment of a 2006 Gas Distribution Access Rule Costs Deferral Account. The 2006 GDAR account is intended to record all incremental unbudgeted costs associated with the development, implementation, and operation of the Gas Distribution Access Rule. Such costs would include, but not be limited to, market restructuring oriented customer education and communication programs, legal or expert advice required in relation to the establishment of contractual agreements and developing revised business processes and related computer hardware and software required to meet the requirements of the GDAR. The balance of the account would be disposed of in a manner to be designated by the Board in a future hearing.

13.1.2 A separate Board proceeding, RP-2000-0001, is considering the GDAR Service Agreement and Electronic Business Standards particulars and implementation target dates. On November 15, 2005, the Board issued a Decision and Order regarding the requirement for the development of a Board-approved form of Service Agreement to be entered into between a gas distributor and each gas vendor that provides or intends to provide gas supply services to consumers in the gas distributor's franchise area. The Decision and Order also addressed the development and implementation of an electronic business transaction system.

13.1.3 The Board noted in this Decision and Order that any rate implications associated with implementation of new regulatory requirements:

> …are properly addressed in a rate proceeding duly convened for that purpose. While the Board cannot in this proceeding predetermine the

> outcome of such a rate proceeding, the Board expects that costs reasonably incurred and directly attributable to the implementation of Board-mandated requirements, such as those embodied in the Service Agreement and the EBT Standards Appendix, would be recoverable through rates in the normal course.

13.1.4 The Board also decided that a delay in the implementation of the Service Agreement and the EBT Standards Appendix beyond January 1, 2006 is appropriate and that implementation should occur in two stages. Functionality for rate-ready Distributor Consolidated Billing ("DCB") and for all transactions necessary to provide full consumer mobility (system gas-to-gas vendor, gas vendor-to-gas vendor and gas vendor-to-system gas switching) must be implemented by January 1, 2007. Functionality for bill-ready DCB must be implemented by January 1, 2008.

13.1.5 The Decision and Order also referred to Enbridge's submission that there could be a cost saving if implementation were to coincide with implementation of its new Customer Information System, which is expected to be in operation by 2008. The Board, as part of that proceeding, has issued a Notice of Proposed Amendments to GDAR setting out the aforementioned implementation dates.

13.1.6 The Company indicated in this proceeding that it will work to implement the required technological changes and processes which support GDAR within the prescribed timelines.

13.1.7 The Council argued that the interests of small volume customers have not been heard with respect to the concern that they may largely bear the costs of GDAR implementation. The Council stated that it rejects Enbridge's proposition that all costs associated with GDAR implementation and ongoing operation should be fully recovered in rates.

13.1.8 Schools submitted that Enbridge should be required to file detailed implementation plans, including operating and capital costs.

13.2 BOARD FINDINGS

13.2.1 As indicated in the Service Agreement proceeding, the Board anticipates that implementation of full GDAR functionality may be more appropriately implemented in stages. This aspect of the decision in that case is particularly germane to this case.

13.2.2 The Board expects the Company to manage the development and implementation of the new CIS system so that its roll-out, and full GDAR compliance, will occur within the times currently represented. As a condition of its approval of the deferral account, the Board will require that the Company provide a detailed timetable for GDAR implementation, which also reflects relevant milestones in the development and implementation of the new CIS. This timetable should also provide detail as to the specific quantum and timing of costs incurred by the Company in implementing GDAR , as distinct from CIS program elements of general application.

13.2.3 The Board reminds parties that the Board's approval of a deferral account, such as the subject GDAR expenses account, does not represent any degree of pre-approval of the inclusion of amounts in the account into rates. While it is reasonable for the Company to anticipate that reasonable expenses incurred in implementing GDAR will be approved, given that compliance with the program is a Board requirement, the specific disposal of the account is to be determined by a future Board panel. This consideration is especially important given that there may be issues respecting the degree to which specific elements of the new CIS can be exclusively or substantially attributed to GDAR implementation.

13.2.4 A similar reservation applies to the appropriate allocation of GDAR costs among Enbridge rate classes. The 2006 Settlement Proposal specifically provided for disposal of the account only when the issues surrounding the appropriate allocation of the costs have been resolved. The Board's Decision herein respects that Settlement Proposal, and the Board will make no order disposing of the account absent a full and fair opportunity for affected parties to make their views known to the Board.

14. DEFERRAL AND VARIANCE ACCOUNTS

14.1 HISTORICAL ACCOUNTS

14.1.1 The amounts, treatment and disposition of historical deferral and variance account balances were resolved in the 2006 Settlement Proposal except for the following:

- 2005 Ontario Hearing Costs Variance Account ("2005 OHCVA")
- 2005 Late Payment Penalty Revision Deferral Account ("2005 LPPRDA")
- 2005 Transactional Service Deferral Account ("2005 TSDA")
- 2002 DSM Variance Account ("2002 DSMVA")
- 2003 DSM Variance Account ("2003 DSMVA")

14.2 2005 ONTARIO HEARING COSTS VARIANCE ACCOUNT

14.2.1 This issue, as described in the 2006 Settlement Proposal, only applies to the Appeal costs and re-hearing costs, if any, attributable to the Alliance/Vector remand proceeding. The questions to be determined are first, whether the costs are properly recorded in the 2005 OHCVA; and second, the appropriate disposition of those costs. Pending resolution of these questions, the Company will not clear any of the costs recorded in the 2005 OHCVA that relate to the Alliance/Vector review, but will clear the balance of the amounts recorded.

14.2.2 In March 2005, the Ontario Divisional Court granted the Company the right to have the issue of disallowed Alliance/Vector costs remitted back to a differently constituted Board panel for reconsideration. The Board sought leave to appeal from the Divisional Court decision and the Ontario Court of Appeal granted the Board leave in July 2005. The appeal is scheduled to be heard in March 2006.

14.2.3 The Company believed that, having won the right to have the issue of the disallowed Alliance/Vector costs reconsidered by the Board, the costs of defending itself against the Board's appeal to the Ontario Court of Appeal and any costs of a subsequent rehearing are properly and fairly recordable and recoverable within the OHCVA. A number of intervenors disagreed with the Company's proposal regarding the recording and disposition of these costs.

14.3 BOARD FINDINGS

14.3.1 The Board agrees with the submission of Energy Probe to the effect that the account as presently structured and defined does not include costs incurred for review proceedings outside of the Board's own Section 44 review procedure. As a rule, deferral accounts should be carefully defined, and the amounts entered should fall clearly within that definition. Imprecise practice in this area will only lead to disputes. Therefore, Enbridge should apply for a new deferral account, which is specifically defined to capture the costs associated with the Judicial Review process at Divisional Court and any appeal proceedings thereafter.

14.3.2 While it is unnecessary for the purposes of our Decision in this case, it is appropriate for the Board to comment upon some of the submissions made respecting the considerations that should apply when considering the disposition of costs related to appeals of Board decisions.

14.3.3 In our view, the question of the prudence of the expenditure is not dependent on the success or failure of the review pursued by the Company; nor is the primary consideration whether the aspect appealed from inures to the benefit of the shareholder or the ratepayer. The determination of the prudence of the expenditure will turn on the reasonableness of the grounds for the review, the reasonableness of the costs incurred, including the relationship of the costs incurred to the likely outcome (which includes such intangibles as precedent, clarification of the law and corporate reputation), and the extent to which the Company can show that it prosecuted its case diligently and efficiently. Clearly, costs incurred in the pursuit of frivolous cases will not be easily recovered. Similarly, where costs are high in pursuit of returns which are comparatively low, marginal, or narrow, the Company will have difficulty in securing recovery. But failure in a reasonable cause should not disqualify attendant costs.

14.3.4 The rate structure in Ontario is predicated on a just and reasonable standard. Where a utility acting in good faith regards a Board decision to be unsound, it should be open to it to bring a Judicial Review action, and to have a prospect of recovery of the associated costs. Each instance will have to be considered on a case by case basis, and these comments are not intended in any way to colour a prudence review of this or any of the other deferral accounts relevant to this case.

14.4 2005 LATE PAYMENT PENALTY REVISION DEFERRAL ACCOUNT

14.4.1 On July 7, 2005, Enbridge filed an application with the Board requesting the establishment of a deferral account to record the costs Enbridge will incur to comply with the Board's direction of September 30, 2004 requiring Enbridge to switch from a 2% one-time late payment penalty to a 1.5% per month late payment penalty. The application was given docket No. EB-2005-0437. In response to comments from the parties during this proceeding, the Board determined that the application will be considered as an issue in this proceeding.

14.4.2 Enbridge indicated that the costs to institute the necessary system changes will be in the range of $620,000 and that $160,000 in additional revenue would be generated in 2005 as a result of implementing the new methodology. The Company took the view that recording the costs in a 2005 deferral account and disposing of them in 2006 was supported by recognized regulatory principles. The Board directed Enbridge to implement a change in the Late Payment Penalty methodology, and the timing of the direction precluded the Company from including the associated costs in its 2005 Test Year rates application.

14.4.3 Generally, the intervenors disagreed with Enbridge's proposal because deferral accounts should only be used in exceptional cases, the incremental revenue resulting from the change should be taken into account, and the amount is not material.

14.5 BOARD FINDINGS

14.5.1 The Board considers that the amount involved in this proposed deferral account is immaterial. The fact that the Board has issued a directive does not itself mandate that a deferral or variance account be established, where one would not, but for the direction, be appropriate. The Board's direction did not require that a deferral account be established, and none is appropriate given the small amount of money involved.

14.6 2005 TRANSACTIONAL SERVICE DEFERRAL ACCOUNT

14.6.1 The sole issue, as described in the 2006 Settlement Proposal, regarding the 2005 TSDA is that intervenors are waiting for a response from Enbridge relating to entries made to the account for any transaction unwinding costs. The allocation of responsibility for unwinding costs may become an issue if the amounts are material.

14.6.2 Enbridge indicated that the total unwinding costs recorded in the 2005 TSDA are $678,000 and that there is $5 million in revenue recorded in the 2005 TSDA which would not have flowed to the 2005 TSDA if the transaction that had unwinding costs associated with them had not been undertaken. Enbridge submitted that is appropriate for the unwinding costs to be included in the amount to be cleared because they are related to the revenue in the account.

14.6.3 Only one intervenor, Energy Probe, addressed the issue in argument and submitted that the unwinding costs are not material and therefore this item should no longer be considered an issue.

14.7 BOARD FINDINGS

14.7.1 The Board notes that no intervenors have argued that unwinding costs are not integral to the Transactional Services activity or that the costs should not be netted against revenues. Accordingly, the Board expects Enbridge to include its proposed disposition of the 2005 TSDA balance, net of unwinding costs, in its draft rate order.

14.8 DEMAND SIDE MANAGEMENT ACCOUNTS

14.8.1 The recovery of the DSMVA for 2002 and 2003 was addressed in the Partial Decision with Reasons issued on December 22, 2005. The Board approved the clearance of $252,000 recorded in the 2002 DSMVA and $1,008,000 in the 2003 DSMVA plus interest.

14.9 2006 ACCOUNTS

14.9.1 The continuation or establishment of deferral and variance accounts for 2006 proposed by Enbridge was resolved in the 2006 Settlement except for the following:

- 2006 Customer Communication Plan Deferral Account ("2006 CCPDA")
- 2006 Corporate Cost Allocation Methodology Deferral Account ("2006 CCAMDA")
- 2006 Manufactured Gas Plant Variance Account ("2006 MGPDA").
- 2006 Demand Side Management Variance Account ("2006 DSMVA-Operating")
- 2006 Shared Saving Mechanism Variance Account ("2006 SSMVA")
- 2006 Lost Revenue Adjustment Mechanism Variance Account ("2006 LRAM")
- 2006 Transactional Services Deferral Account ("2006 TSDA")

14.10 2006 CUSTOMER COMMUNICATION PLAN DEFERRAL ACCOUNT ("2006 CCPDA")

14.10.1 CCPDA-type deferral accounts have existed since the late 1990's at which time there were significant developments in the direct purchase market in Ontario. Enbridge submitted that the degree of instability in gas commodity prices and the outcomes of the Natural Gas Forum may impact the availability and purpose of system gas and this may lead to a real need for the Company to communicate with customers to ensure they understand their options and any resulting implications. Enbridge further submitted that it is appropriate to establish a CCPDA for 2006 because of the prospects for significant change and confusion in the natural gas market and because the Company is unable to reasonably budget for such impacts.

14.10.2 Intervenors opposed Enbridge's proposal because it is based on vague expectations, the CCPDA account has been inactive for a number of years and the Company should manage its communications requirements with its O&M communications budget.

14.11 BOARD FINDINGS

14.11.1 The Board finds that the account should be terminated. Such communications as are needed can be reliably handled within the substantial existing customer communications budget within the total O&M budget.

14.12 2006 CORPORATE COST ALLOCATION METHODOLOGY DEFERRAL ACCOUNT

14.12.1 The Company is requesting the continuation of the 2005 CCAMDA, consistent with the Board allowed deferral account recovery of costs of an independent audit review of its corporate cost allocation methodology as directed in the RP-2002-0133 proceeding. Enbridge anticipated that the Board may require a further review or variation to the proposed new RCAM methodology.

14.12.2 Intervenors expressed concern with the need for a further review at rate-payer expense and considered the establishment of a deferral account, prior to Board-directed determination that a review is required, premature.

14.13 BOARD FINDINGS

14.13.1 In Chapter 10 of this Decision the Board finds that an independent evaluation is critical to the RCAM methodology refinements that Enbridge should undertake, and that the cost of the evaluation should be borne by ratepayers. Accordingly, the Board approves the establishment of a 2006 CCAMDA solely for the purpose of recording the costs the independent evaluation.

14.14 2006 MANUFACTURED GAS PLANT VARIANCE ACCOUNT

14.14.1 This issue was previously considered by the Board in the RP-2002-0133 proceeding. In that proceeding the Board did not approve the establishment of a 2003 MGPVA on the basis that "… the evidence presented in this proceeding is not adequate to convince the Board that a deferral account of either a generic or specific nature is required at this time". The Board indicated its concern that "… the mere existence of the deferral account may imply an expectation of future recovery by the Company" and noted that "the applicant may reapply in the future for a MGPDA with greater details on the scope, potential costs, and grounds for any ratepayer responsibility for these costs." (RP-2002-0133 Decision par 753-755).

14.14.2 Enbridge noted that a litigant, Cityscape Residential Inc., is once again prosecuting its lawsuit and that there is a substantial probability that a trial will occur in 2006. For this and other reasons the Company is seeking approval for the establishment of a 2006 MGPVA. Enbridge proposed that the 2006 MGPVA record all external costs associated with:

- Responding to all enquiries, demands and court actions relating to former MGP sites;
- All oral and written communications with existing and former third party liability and property insurers of the Company;
- Conducting all necessary historical research and reviews to facilitate the Company's responses to all enquiries, demands, court actions and communications with claimants, third parties and insurers;
- Engaging appropriate experts (for example, environmental, insurance archivists, engineers, etc.) for the purposes of evaluating any alleged contamination that may have resulted from former Manufactured Gas Plant ("MGP") operations, and appropriate steps to remediate/contain/monitor such contamination, if any;

- Engaging legal counsel to respond to all demands and court actions by claimants, and to take appropriate steps in relation to the Company's existing and former third party liability and property insurers; and

- Undertaking appropriate research into the regulatory treatment of costs resulting from former MGP operations in the United States.

14.14.3 The MGPVA would also be used to record any amounts which are payable to any claimant following settlement or trial, including any damages, interest, costs and disbursements and any recoveries from insurers or third parties.

14.14.4 The Company submitted that the establishment of the MGPVA is justified because it meets the four criteria of

- materiality

- protection of the ratepayer and shareholder from benefiting at the expense of the other

- level of uncertainty associated with the forecast amount at risk and

- Company's ability to control the potential outcomes of the legal proceeding.

14.14.5 Intervenors disagreed with the proposal to establish the MGPVA and, if the account were to be established, the range of costs to be recorded. Intervenors also expressed concern that it was not clear whether Enbridge is requesting approval from the Board in principle for the recovery of the recorded costs from ratepayers. The intervenors claimed that there is insufficient and incomplete evidence upon which to grant such approval.

14.14.6 Enbridge clarified that it is requesting approval for the establishment of the variance account for amounts which it has identified specifically in its pre-filed evidence. It confirmed its expectation that the amounts recorded in the variance account would be subject to Board scrutiny in a subsequent proceeding to ensure their prudence before being cleared. Enbridge went on to advance the proposition that a broad range of costs should be recordable in the account, based upon regulated utility practice and precedent in the United States where such costs are considered, as a matter of principle, properly recovered in rates.

14.15 BOARD FINDINGS

14.15.1 It is appropriate to capture the costs incurred in managing and resolving the issues involved in these legacy operations in a deferral account, as requested by the Company.

14.15.2 The extremely complex issue as to whether ratepayers should be responsible for some or all of the possible claims and related costs has yet to be determined, and the creation of this deferral account should not be regarded as predictive of the ultimate resolution of that issue or the disposal of the sums ultimately recorded in the account.

14.15.3 The Board directs that the sum of $770,000, currently included in the O&M budget, be removed from that budget and reflected in the Deferral Account as expenditures are made, pending disposition according to the Board's determination of the underlying issues. The Board approved level of "Other O&M", which has been derived from a cost per customer index, will remain unchanged.

14.16 2006 ONTARIO HEARING COSTS VARIANCE ACCOUNT (2006 OHCVA)

14.16.1 The 2006 OHCVA is a settled item in the 2006 Settlement Proposal. However, some intervenors argued that it appeared that Enbridge was proposing to change the wording of the 2006 OHCVA from what was stipulated in pre-filed evidence, and, in effect agreed to in the Settlement Proposal.

14.16.2 In Exhibit A8 Tab 1 Schedule 1 the 2006 OHCVA is "….to record the variance between actual 2006 rate hearing expense and the budgeted level of $9.95 million as shown in evidence at Exhibit A6 Tab 7 Schedule 4." The Consumers Council of Canada argued that the Board should consider a more defined scope for the deferral account than that which appears in the Settlement Agreement.

14.17 BOARD FINDINGS

14.17.1 The Board understands that this is a settled issue in the 2006 Settlement Proposal. Parties continue to have the opportunity to advance any concerns at the time of the proposed disposition of the amounts recorded in the account.

14.18 OTHER ACCOUNTS

14.18.1 The Board's findings regarding the 2006 TSDA is found in Chapter 6.

14.18.2 The 2006 DSMVA-Operating, 2006 SSMVA and 2006 LRAM have been addressed in the EB-2005-0001 Partial Decision, dated December 22, 2005.

15. RATE IMPLEMENTATION

15.1.1 The Board notes that that the financial impact of the Settlement Proposal is reflected in the "N1, Tab2" series of exhibits filed on August 5, 2005. As a result of the Board's findings contained in this Decision and the Partial Decision dated December 22, 2005, the revenue requirement for the 2006 Test Year will change. Accordingly, the Board directs Enbridge to reflect any changes brought about by the Decisions, including an updated return on equity, in revised financial schedules similar to the "N1, Tab2" exhibits. These exhibits are to be filed as soon as possible.

15.1.2 The matter of retroactive recovery of the Board determined revenue deficiency was an unsettled issue. Enbridge is seeking full recovery of any revenue deficiency found by the Board and has suggested alternative methodologies to accomplish this. VECC, Schools and CME opposed any retroactivity, but IGUA did not.

15.1.3 This proceeding involved a number of difficult issues which added to its complexity and length. The Board is not convinced by the arguments of some intervenors that there should not be full recovery of the revenue deficiency. Accordingly, the Board has considered the alternatives provided by Enbridge and finds that the revenue deficiency that otherwise would have been recovered during the January 1, 2006 to March 31, 2006 period is to be recovered by way of a one-time retroactive adjustment. The unit charge, for each rate class, will be calculated using January 1, 2006 to March 31, 2006 forecasted volumes as approved in this Decision. The unit charge will be applied to actual volumes so as to best approximate the outcome had the 2006 rates been implemented commencing January 1, 2006.

15.1.4 Given the timing of this Decision, the Board expects that the new rates would be implemented on or before April 1, 2006.

15.1.5 Accordingly, the Board requires Enbridge to file a draft rate order, including unit rates for the one-time retroactive adjustment, by March 8, 2006. Intervenors wishing to comment on the draft rate order are to file their submissions by March 15, 2006.

16. COST AWARDS

16.1.1 The Board in its Partial Decision on Cost Awards dated December 14, 2005 ("the Partial Decision") found that the Council, IGUA, Energy Probe, GEC, Pollution Probe, CME, VECC, OAPPA, and Schools should be awarded 100% of their reasonably incurred costs up to the end of the evidentiary portion of the hearing. The Board further directed that these costs were to be paid by Enbridge upon receipt of the Board's Cost Orders. Cost Award Orders have been issued in this regard. The Board will issue its costs award decision on the argument potion of the hearing under separate cover.

DATED at Toronto February 9, 2006

Original signed by

Pamela Nowina
Vice Chair and Presiding Member

Original signed by

Paul Sommerville
Member

Original signed by

Cynthia Chaplin
Member

APPENDIX 1

ENBRIDGE GAS DISTRIBUTION INC.

2006 TEST YEAR

DECISION WITH REASONS

BOARD FILE NO. EB-2005-0001/EB-2005-0437

PROCEDURAL DETAILS INCLUDING LISTS OF PARTIES AND WITNESSES

FEBRUARY 9, 2006

PROCEDURAL DETAILS INCLUDING LISTS OF PARTIES AND WITNESSES

THE PROCEEDING

On April 13, 2005, the Board issued a Notice of Application which was published and served in accordance with the Board's direction.

The Board issued Procedural Order No.1 on May 6, 2005, establishing the procedural schedule for all events prior to the oral hearing. These events included:

- Issues conference on May 17, 2005;
- Issues Day on May 19, 2005;
- Written interrogatories to the Applicant by May 26, 2005;
- Written interrogatory responses from the Applicant by June 16, 2005;
- Intervenor evidence filed by June 23, 2005;
- Written interrogatories on Intervenor evidence by June 30, 2005;
- Responses to written interrogatories on Intervenor evidence by July 8, 2005;
- Motions objecting to sufficiency of any interrogatory response by July 12, 2005;
- Intervenor Conference on July 18, 2005;
- Settlement Conference beginning July 19, 2005;
- Settlement Proposal by August 5, 2005;
- Board review of Settlement Proposal on August 15, 2005.

In response to Procedural Order No. 1, the Board received written evidence prepared by the following parties:

- F.S. Rick Thomas on behalf of the Canadian Natural Gas Vehicle Alliance (“CNGVA”);
- Jim Stephens on behalf of the Consumers Council of Canada (“Council”), the Industrial Gas Users Association (“IGUA”) and the Vulnerable Energy Consumers Coalition (“VECC”);
- Randy Aiken on behalf of Energy Probe Research Foundation;
- Tom Adams on behalf of Energy Probe Research Foundation;
- Chris Neme on behalf of the Green Energy Coalition (“GEC”);
- Peter Fournier on behalf of the IGUA;
- Hugh W. Johnson on behalf of VECC, the Council, IGUA, School Energy Coalition (“Schools”).

On Issues day, the Board heard submissions from Enbridge, Pollution Probe, IGUA, the Council, Direct Energy Marketing Limited, Superior Energy Management (“SEM”), TransAlta Cogeneration LP, TransAlta Energy Corp, Advocates for Fair and Non-Discriminatory Access, Ontario Energy Savings Corp. GEC, Heating, Ventilation and Air-Conditioning Coalition Inc., Canadian Manufacturers & Exporters, Ontario Association of Physical Plan Administrators, TransCanada Pipelines, Energy Probe, Schools, Jason Stacey, and VECC. On May 20, 2005, the Board issued Procedural Order No. 2, which established the Issues List for the proceeding.

Procedural Order No. 3, issued May 30, 2005, made the following schedule changes:

- Motions regarding the sufficiency of any filed interrogatory response by June 23, 2005;
- Board hearing, if any, of June 23, 2005 motions on June 29, 2005.

Procedural Order No. 4, issued June 24, 2005, made the following schedule changes:

- Motions regarding the sufficiency of any filed interrogatory response by June 27, 2005;
- Intervenor evidence filed by June 29, 2005;
- Written interrogatories on Intervenor evidence by July 6, 2005;
- Responses to written interrogatories on Intervenor evidence by July 13, 2005.

On October 28, 2005, the Board issued Procedural Order No. 5, which set dates for a written hearing to consider a motion brought by the School Energy Coalition.

On November 8, 2005, the Board issued Procedural Order No. 6, which set dates for a written motion to consider costs awards for the evidentiary portion of the proceeding.

The Settlement Conference commenced on July 19, 2005 and concluded on July 29, 2005. The following parties participated: Enbridge Gas Distribution Inc., Ontario Energy Savings Corp., Consumers Council of Canada, Jason F. Stacey, Ontario Association of Physical Plant Administrators, Canadian Manufactures and Exporters, Energy Probe Research Foundation, Union Gas Limited, ECNG Limited Partnership, TransCanada PipeLines Limited, Green Energy Coalition, Direct Energy Marketing Limited, Vulnerable Energy Consumers' Coalition, School Energy Coalition, Pollution Probe Foundation, Industrial Gas Users Association.

MOTION BY SCHOOL ENERGY COALITION

On October 14, 2005, Schools filed a Motion Record seeking an Order by the Board varying two undertakings of confidentiality signed by counsel for Schools: one from this proceeding and one from the RP-2002-0133 proceeding.

On October 28, 2005, the Board issued Procedural Order No. 5, which set dates for a written hearing to consider School's motion. The Board issued its decision, denying the motion, on January 31, 2006.

PARTICIPANTS AND REPRESENTATIVES

Below is a list of participants and their representatives that were active either at the oral hearing or at another stage of the proceeding. A complete list of intervenors is available at the Board's offices.

Board Counsel and Staff	Michael Millar Richard Battista Colin Schuch Rudra Mukherji Michael Bell
Enbridge Gas Distribution Inc.	Fred Cass Dennis O'Leary Tania Persad Richard Lanni David Stevens
Pollution Probe	Murray Klippenstein
Industrial Gas Users Association ("IGUA")	Peter Thompson Vince DeRose
Consumers Council of Canada ("the Council")	Robert Warren
Direct Energy	Ian Mondrow Evangelia Kriaris Eric Hoaken
Superior Energy Management	Elizabeth DeMarco Avril Cole
TransAlta Cogeneration LP, TransAlta Energy Corp, Advocates for Fair and Non-Discriminatory Access	Elizabeth DeMarco
Ontario Energy Savings Corp	Nola Ruzycki
Green Energy Coalition	David Poch
Heating, Ventilation and Air-Conditioning Coalition Inc. ("HVAC Coalition"), Canadian Manufacturers & Exporters ("CME")	Brian Dingwall
Ontario Association of Physical Plant Administrators	Valerie Young

TransCanada PipeLines	Murray Ross Alan Ross
Energy Probe	David Macintosh Tom Adams
School Energy Coalition (“Schools”)	Jay Shepherd
Natural Gas Specialist	Jason Stacy
Vulnerable Energy Consumer’s Coalition (“VECC”)	John DeVellis Michael Janigan
ConsumerWorks Limited Partnership LLP	Margaret Sims Sandy Robinson
Accenture Business Services for Utilities Inc.	Ava Kanner Robert J. Howe
Terasen Inc.	Anna K. Fung

WITNESSES

There were 63 witnesses who testified at the oral hearing. The following Company employees and Enbridge Inc. employees appeared as witnesses at the oral hearing:

Don Small	Manager, Gas Cost Knowledge Centre
Arunas Pleckaitis	Vice President, Operations
Janet Holder	Vice President, Market Services
Lloyd Chiotti	General Manager, EnVision Program
Catherine McCowan	Manager, Operation Services
Dennis Bruce	Vice President, HLB Decision Economics
Fred Rubino	Manager, Supply Services, Energy Policy and Analysis Department
David Charleson	Director, Energy Policy and Analysis
Jim Schultz	President

Tom Ladanyi	Manager, Budgets and Planning
Glenn Beaumont	Vice President, Engineering
Malini Giridhar	Manager, Rate Research and Design of the Company
Jackie Collier	Manager, Rate Design
Bonnie Dupont	Group Vice President, Corporate Resources
Scott Player	Vice President, Finance
Mike Mees	Director, Customer Care (formerly the Director, Planning and Governance)
Colin Gruending	Vice President and Controller
David Brown	Director, Controllers' Projects
Brad Boyle	Treasury Group
Jane Haberbush	Director, Human Resources
Marc Lattoni	Vice President, Human Resources
Byron Neiles	Vice President, Legal Regulatory, Public and Government Affairs
Lino Luison	Vice President, Opportunity Development
Chuck Szmurlo	Vice President, Energy Technology and Business Development
Jody Sarnovsky	Manager, Strategic and Key Accounts
John Briggs	Manager, Budgets Administration, Operations Department
Jamie Milner	General Manager, Eastern Region
Marika Hare	General Manager, Central Region
Liz Stokes-Bajcar	Manager, of Human Resources Service Centre and Compensation

Annette Urquhart	Manager, Corporate Budgets and Planning
Debbie Kelly	Manager, Operational and Capital Budgets
Kevin Culbert	Manager, Regulatory Accounting
Stephen McGill	Manager, Strategic Projects
Patrick Hoey	Director, Regulatory Affairs
Mark Boyce	Associate General Counsel and Corporate Secretary
John Bayco	Director, Sustainable Growth
Susan Clinesmith	Manager, Business Markets and Communications Development
Norman Ryckman	Group Manager, Business Intelligence and Support
Tom Jedemann	Manager, New Construction and Mass Market Development
Kerry Lakatos-Hayward	Manager, Strategic Planning and Development
George DeWolf	Director, Information Technology
Rob Fox	Chief Engineer, Engineering
John Hodgens	Manager, Facility Services for the Company
Doug Lapp	Chief Operations and Logistics Engineer
Debbie Boukydis	Manager, Public and Government Affairs
Rob Milne	
Sagar Kancharla	Manager, Financial and Economic Assessment
Tanyia Ferguson	Manager, Special Projects, Customer Support

Gerald Scott Dodd	Director, Planning and Economics
Michael Brophy	Manager, DSM and Portfolio Strategy
Steven Poff	former Manager, DSM and Program Delivery
Steve Letwin	Group Vice-President, Gas Strategy and Corporate Development
Mark Boonstra	Senior Advisor, Planning and Economics

In addition, the Company called the following witnesses:

Gabor Toth	Chartered Accountant, Deloitte Inc.
Andre Pienaar	Certified Management Consultant, Deloitte Inc.
Eric Krathwohl	Attorney, Rich May
Stephen Dick	Senior Consultant, MICON Consulting
Gordon Barefoot	Senior Vice-President Finance and Chief Financial Officer, Terasen Inc.

Witnesses called by Intervenors:

Chris Neme	Vermont Energy Investment Corporation
Amy-Lynne Williams	Deeth, Williams, Wall
Jim Stephens	Stephens Consulting Ltd.
Tom Adams	Executive Director, Energy Probe Research Foundation
Peter Fournier	President, Industrial Gas Users Association

APPENDIX 2

ENBRIDGE GAS DISTRIBUTION INC.

2006 TEST YEAR

DECISION WITH REASONS

BOARD FILE NO. EB-2005-0001/EB-2005-0437

SETTLEMENT PROPOSAL
(DATED AUGUST 10, 2005)

FEBRUARY 9, 2006

SETTLEMENT PROPOSAL

AUGUST 10, 2005

TABLE OF CONTENTS

ISSUE	DESCRIPTION (& EVIDENTIARY REFERENCE)	PAGE
	PREAMBLE	8
1	**GAS VOLUME & REVENUE FORECAST**	
1.1	Gas Volume Budget	11
1.2	Average use Forecast for Rate Class 1	12
1.3	Average use forecast for Rate Class 6	12
1.4	Budget Degree Days – Proposal to change to the DeBever With Trend Forecasting Methodology	13
2	**OTHER REVENUE**	
2.1	Appropriateness of the Forecast of Other Service Revenue	14
3	**TRANSACTIONAL SERVICES**	
3.1	Gross Margin forecast	14
3.2	Proposed new sharing mechanism for Transactional Services for 2006	15
3.3	Enbridge Gas Services (EGS) and Enbridge Operational Services (EOS) Services Agreements, as they relate to the provision of Transactional Services, to the extent not dealt with in EB-2005-0244.	15
4	**CLASS ACTION SUIT DEFERRAL ACCOUNT**	
4.1	Recovery of amounts (estimated at $1.725 million) in the 2005 Class Action Suit Deferral Account (2005 CASDA)	15
4.2	Request to establish a 2006 CASDA	16
5	**LATE PAYMENT PENALTY**	
5.1	Compliance with Board's September 30, 2004 directive to switch from a 2% one-time penalty to a 1.5% monthly interest LPP, including the	17

ISSUE	DESCRIPTION (& EVIDENTIARY REFERENCE)	PAGE
	request for a deferral account to capture 2005 implementation costs, and the recovery of those costs in 2006.	
6	**GAS COSTS, TRANSPORTATION & STORAGE**	
6.1	Gas, Transportation and Storage Costs	17
6.2	2005 Implementation of Enbridge Gas DistributionI Gas Supply Risk Management Program Recommendations	18
6.3	2006 Implementation Plans for Enbridge Gas DistributionI Gas Supply Risk Management Program Recommendations	18
6.4	Implications of, and the report on, Customer Threshold for Gas Supply Volatility Study	18
7	**COST OF CAPITAL**	
7.1	Estimates of the cost and mix of short-term and long-term debt for the 2006 Test Year	18
7.2	Determination of calendar ROE for the 2006 Test Year using the Board's Guidelines	19
7.3	Appropriateness of including any standby credit fees in the Cost of Capital, and in the alternative, the amount thereof.	20
8	**RATE BASE**	
8.1	Capital Budget for the 2006 Test Year including capitalized O&M expenses	21
8.2	Information Technology Capital Budget including Energy Transaction, reporting, Accounting and Contracting (EnTrac), and Meter management and Large volume Meter Data Processing (EnMar) projects	21
8.3	Appropriateness of the capital budget "placeholder" for power generation project RFPs	21

8.4 Appropriateness of the capital budget for System Improvements and Upgrades, including the budget increases in system expansion and reinforcement projects and the Accelerated Bare Steel and Cast Iron Replacement Program 21

9 2006 OPERATIONS & MAINTENANCE BUDGET

9.1 Overall O&M levels for 2006 22

9.2 O&M – Finance 22

9.3 O&M – Customer Support 22

9.4 O&M – Customer Care – Customer Works Limited Partnership & Enbridge Commercial Services Segmented Financial Statements 22

9.5 O&M – CIS Replacement 22

9.6 O&M – Customer Care Cost Update 22

9.7 O&M – Engineering Department 22

9.8 O&M – Opportunity Development, including electricity to gas fuel switching activities 22

9.9 O&M – Natural Gas for Vehicles (NGV) 22

9.10 O&M – Gas Storage Operations 22

9.11 O&M – Regional Operations 22

9.12 O&M – Strategic and Key Accounts 22

9.13 O&M – Human Resources 22

9.14 O&M – Legal, Regulatory and Public Affairs 22

9.15 O&M – Information Technology Department 22

9.16 Non-Departmental O&M expenses 22

9.17 Corporate Cost Allocations including Deloitte Evaluative Report 22

9.18	O&M Affiliate Transactions and Non-Utility Elimination	22
9.19	Third party access to customer bills (excluding ABC-T billing service including its revenue and cost impacts)	22
10	**NATURAL GAS VEHICLES**	
10.1	Review of NGV program	23
11	**ENVISION PROJECT**	
11.1	ENVISION Project including HLB Decision Economics Inc. Interim Final Opinion: Review of EnVision Benefits Realization Plan and Contract	23
12	**ENTRAC (Energy Transaction Reporting, Accounting & Contracting)**	
12.1	EnTrac Master Service Agreements (User Agreement, Gas Delivery Agreement, etc.), including the appropriateness of the terms and conditions for access to EnTrac.	26
13	**GAS DISTRIBUTION ACCESS RULE**	
13.1	Impact Of the Gas Distribution Access Rule on capital and Operating plans and expenditures.	26
14	**TAXES**	
14.1	Derivation of Income, Large Corporation, Capital and Municipal Property Tax amounts	26
15	**DEMAND SIDE MANGEMENT**	
15.1	Proposal for a 3 year term (2006-2008) DSM Plan, including the O&M budgets and the volume targets	27
15.2	Attribution of benefits in jointly delivered DSM programs	27
15.3	Proposal to change Demand Side Management Variance Account mechanics	27
15.4	Market Transformation Programs and Incentives	27

15.5 Proposed Shared Savings Mechanism (SSM) incentive model for 2006 27

15.6 Recovery of SSM and Lost Revenue Adjustment Mechanism (LRAM) amounts for 2002 and 2003 28

15.7 Recovery of DSMVA for 2002 and 2003 28

16 DEFERRAL & VARIANCE ACCOUNTS

16.1 Amounts and proposed disposition of balances in historic deferral and variance accounts 28

16.2 Request to continue or establish new deferral and variance accounts for 2006 31

16.3 Request to establish a 2006 Notional Utility Account Deferral Account 33

16.4 Request to establish a 2006 Manufactured Gas Plant Variance Account 33

17 COST ALLOCATION

17.1 2006 Cost Allocation 33

17.2 Changes in revenue to cost ratios 34

18 RATE DESIGN

18.1 Proposal for changes to the Rate Handbook 35

18.2 Direct Purchase Administration Charge and System Gas fees 35

18.3 Timing and changes to all aspects of Enbridge Gas DistributionI's Rate 300, 305, 310 & 315 rate schedules 36

18.4 2006 Revenue Deficiency allocation 36

18.5 Review of the rate impacts including Year 2 phase-in of Cost Allocation changes and material changes, if any, from RP-2005-0001 Settlement Proposal (Ref: clause 15.4) 37

19 RATE IMPLEMENTATION

19.1 Year 2 phase-in of cost allocation changes for upstream transportation, storage, peaking service and interruptible credits 37

19.2 Implementation of any other rate design changes 38

19.3 Timing of implementation of 2006 rates 38

ATTACHMENTS

Appendix A - Table 1 - Interest Rate Forecasts

Appendix B - Deferral and Variance Accounts Balances

PREAMBLE

This Settlement Proposal is filed with the Ontario Energy Board ("OEB" or "Board") in connection with the application of Enbridge Gas Distribution Inc., for an order or orders approving or fixing rates for the sale, distribution, transmission, and storage of gas for its 2006 fiscal year (the "Test Year").[1] A Settlement Conference was held from July 19 to July 29, 2005 in accordance with the *Ontario Energy Board Rules of Practice and Procedure* (the "Rules") and the Board's *Settlement Conference Guidelines* ("Settlement Guidelines"). This Settlement Proposal arises from the Settlement Conference.

Enbridge Gas Distribution Inc. ("Enbridge Gas Distribution" or the "Company") and the following intervenors (collectively, the "parties"), as well as Ontario Energy Board technical staff ("Board Staff"), participated in the Settlement Conference:

ADVOCATES FOR FAIR AND NON-DISCRIMINATORY ACCESS (Advocates)
CANADIAN MANUFACTURERS & EXPORTERS (CME)
CONSUMERS COUNCIL OF CANADA (CCC)
DIRECT ENERGY MARKETING LIMITED (DEML)
ECNG LIMITED PARTNERSHIP (ECNG)
ENERGY PROBE RESEARCH FOUNDATION (Energy Probe)
GREEN ENERGY COALITION (GEC)
HVAC COALITION INC. (HVAC)
INDUSTRIAL GAS USERS ASSOCIATION (IGUA)
J. STACEY
ONTARIO ASSOCIATION OF PHYSICAL PLANT ADMINISTRATORS (OAPPA)
ONTARIO ENERGY SAVINGS CORP. (OESC)
POLLUTION PROBE
SCHOOL ENERGY COALITION (Schools)
SUPERIOR ENERGY MANAGEMENT (a division of Superior Plus Inc.) (Superior)
TRANSALTA COGENERATION L.P. AND TRANSALTA ENERGY CORP. (TransAlta)
TRANSCANADA ENERGY CORPORATION (TEC)
TRANSCANADA PIPELINES LIMITED (TransCanada)
UNION GAS LIMITED (Union)
VULNERABLE ENERGY CONSUMERS COALITION (VECC)

The Settlement Proposal deals with all of the issues listed at Appendix "A" to the Board's Procedural Order #2, dated May 20, 2005 (the "Issues List"). The numbers ascribed to each of the issues correlate to the section numbers in the Settlement Proposal and each issue falls within one of the following three categories:

[1] In this Settlement Proposal, the terms "2006 fiscal year", "fiscal 2006" and "Test Year" each refer to the twelve-month period commencing January 1, 2006 and ending December 31, 2006.

1. ***complete settlement* –** the issue will not be addressed at the hearing because Enbridge Gas Distribution and all other parties who take any position on the issue agree to the proposed settlement;

2. ***partial settlement* –** the issue will be addressed at the hearing because one or more parties who participated in the negotiation of the issue disagree(s) with one or more parts of the proposed settlement of the issue; and,

3. ***no settlement* –** the issue will be addressed at the hearing because the parties who participated in the negotiation of the issue are unable to reach a settlement on the issue.

More particularly, the Settlement Proposal depicts the 67 issues enumerated on the Issues List as follows:

Complete Settlement Parties will not address the issue at the hearing	**Partial Settlement** Parties will address one or more parts of the issue at the hearing	**No Settlement** Parties will address the issue at the hearing
1.1-1.4, 2.1, 3.3, 4.1, 4.2, 7.1-7.3, 14.1, 15.6, portions of 16.1 & 16.2, 16.3, 17.1, 17.2, 18.1, 18.2, 18.4, 18.5, 19.1, and 19.2 24 issues completely settled	10.1 1 issue partially settled	3.1, 3.2, 5.1, 6.1-6.4, 8.1-8.4, 9.1-9.19, 11.1, 12.1, 13.1, 15.1-15.5, 15.7, portions of 16.1 & 16.2, 16.4, 18.3, and 19.3 42 issues not settled

The description of each issue assumes that all parties participated in the negotiation of the issue, unless specifically noted otherwise.[2] Any parties that are identified as not having participated in the negotiations of the issue also take no position on any settlement or other wording pertaining to the issue. In accordance with the Rules and the Settlement Guidelines, Board Staff takes no position on any issue and, as a result, is not a party to the Settlement Proposal.

[2] Pollution Probe, and GEC did not participate in the discussion of any of the settled issues except for issue 15.6. TransCanada, TEC, and J.Stacey did not participate in the discussion of any of the settled issues. OESC participated but took no position in the settlement of issues 2.1, 17.1, 17.2 and 19.2, and participated and agreed with issues 18.1 and 18.2.

The Settlement Proposal describes the agreements reached on the completely settled and partially settled issues. The Settlement Proposal identifies the parties who agree and who disagree with each settlement, or alternatively who take no position on the issue. Finally, the Settlement Proposal provides a direct link between each settled issue and the supporting evidence in the record to date. In this regard, the parties who agree with the individual settlements are of the view that the evidence provided is sufficient to support the Settlement Proposal in relation to the settled issues and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make findings on the settled issues.

This Settlement Proposal proposes that issue 18.2 be considered in the pending Natural Gas Forum generic proceeding on Cost Allocation of Regulated Gas Supply.

Best efforts have been made to identify all of the evidence that relates to each settled issue. The supporting evidence for each settled issue is identified individually by reference to its exhibit number in an abbreviated format; for example, Exhibit A, Tab 8, Schedule 1 is referred to as A-8-1. A concise description of the content of each exhibit is also provided. In this regard, Enbridge Gas Distribution's response to an interrogatory is described by citing the name of the party and the number of the interrogatory (e.g., Board Staff Interrogatory #1). The identification and listing of the evidence that relates to each settled issue is provided to assist the Board. The identification and listing of the evidence that relates to each settled issue is not intended to limit any party who wishes to assert that other evidence is relevant to a particular settled issue.

According to the Settlement Guidelines (p. 3), the parties must consider whether a settlement proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. Enbridge Gas Distribution and the other parties who participated in the Settlement Conference consider that no settled issue requires an adjustment mechanism other than those expressly set forth herein.

Issues 1.1, 1.2, 1.3, 1.4, 2.1, 7.1, 7.2, 10.1, 14.1, and 18.2 have been settled by the parties as a package (the “package”) and none of the provisions of these issues are severable. If the Board does not, prior to the commencement of the hearing of the evidence in EB-2005-0001, accept the package in its entirety, then there is no Settlement Proposal (unless the parties agree that any portion of the package that the Board does accept may continue as part of a valid Settlement Proposal). None of the parties can withdraw from the Settlement Proposal except in accordance with Rule 32 of the Rules. Finally, unless stated otherwise, the settlement of any particular issue in this proceeding is without prejudice to the rights of parties to raise the same issue in any future proceeding.

1 GAS VOLUME & REVENUE FORECAST

1.1 Gas Volume Budget

(Complete Settlement)

There is an agreement to settle this issue (as part of the package) as follows:

The parties agree to a Test Year gas volume budget of 12,320.9 10^6m^3 based on a 3745 degree day forecast.

In its pre-filed evidence at A2-2-1, the Company used its proposed "de Bever Methodology with Trend" to produce a gas volume budget of 12,184.7 10^6m^3 based on 3671 gas supply degree days. The Board approved "de Bever methodology" would have produced a gas volume budget of 12,402.9 10^6m^3 based on 3788 gas supply degree days as would the methodology described in the evidence filed by Energy Probe.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, OAPPA, Superior and TransAlta.

Approval: All participating parties accept and agree with the proposed settlement of this issue except Union, DEML and ECNG who take no position.

Evidence: The evidence in relation to this issue includes the following:

A2-1-1	Gas Volume and Revenue Evidence Summary
A2-2-1	Gas Volume Budget
A2-2-2	Average Use Forecasting Model for Rate 1
A2-2-3	Average Use Forecasting Model for Rate 6
A2-2-5	Budget Degree Days
A2-3-1	Economic Outlook
A2-3-2	Interest Rate and Exchange Rate Forecast November 2004
C1-1-1	Utility Operating Revenue 2006 Test Year
C1-2-1	Customers, Volumes and Revenues by Rate Class 2006 Budget
C1-2-2	Comparison of Average Customer Numbers by Rate Class 2006 Budget and 2005 Estimate
C1-2-3	Comparison of Gas Sales & Transportation Volume by Rate Class 2006 Budget & 2005 Estimate
C1-2-4	Comparison of Gas Sales & Transportation Volume by Rate Class 2006 Budget & 2005 Estimate
C1-2-5	Comparison of Gas Sales & Transportation Revenue by Rate Class 2006 Budget & 2005 Estimate
C3-1-1	Utility Operating Revenue 2004 Historical
C3-1-2	Comparison of Utility Operating Revenue 2004 Actual and 2004 Estimate
C3-2-1	Customers, Volumes and Revenues by Rate Class 2004 Actual
C3-2-2	Comparison of Gas Sales & Transportation Volume by Rate Class 2004 Actual & 2004 Estimate
C3-2-3	General Service Average Use - Historical Normalized and Board Approved - Fiscal Year
C3-2-4	General Service System-Wide Normalized Average Use - Calendar Year
D2-3-1	Unbilled and Unaccounted-for Gas Volumes
D3-3-1	Unbilled and Unaccounted-for Volumes 2004 Actual vs 2004 Estimate
I-1-1 to 35, 56 and 59	Board Staff Interrogatories 1 to 35, 56 and 59
I-2-10	Advocates Interrogatory 10
I-3-2 to 10	CME Interrogatories 2 to 10
I-5-2 to 4	CCC Interrogatories 2 to 4

I-8-1 to 31, 39 and 41 to 43	Energy Probe Interrogatories 1 to 31, 39 and 41 to 43
I-11-14 to 19, 25, 31 and 55	IGUA Interrogatories 14 to 19, 25, 31 and 55
I-18-6 to 11	School Energy Interrogatories 6 to 11
I-23-1 and 2	TransCanada PipeLines Interrogatories 1 and 2
I-25-4 to 13, 30, 32 to 34 and 36	VECC Interrogatories 4 to 13, 30, 32 to 34 and 36
I-29-1 to 10	Enbridge Interrogatories of Energy Probe 1 to 10
L-8-1	Energy Probe Evidence

1.2 Average Use Forecast for Rate Class 1

(Complete Settlement)

There is an agreement to settle this issue (as part of the package) as follows:

> The parties agree, based on the settlement of the Test Year degree day forecast, to a Rate 1 (residential service customer) average use forecast of 2,850 m^3. This number was arrived at by applying the Company's regression models referred to in evidence at A2-2-2, to the gas volume budget and degree day forecast settled in issue 1.1 above.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, OAPPA, Superior and TransAlta.

Approval: All participating parties accept and agree with the proposed settlement of this issue except Union, DEML and ECNG who take no position.

Evidence: The evidence in relation to this issue includes the following:

A2-2-2	Average Use Forecasting Model for Rate 1
A2-2-3	Average Use Forecasting Model for Rate 6
I-1-13 and 20 to 25	Board Staff Interrogatories 13 and 20 to 25
I-8-8 to 10 and 15 to 18	Energy Probe Interrogatories 8 to 10 and 15 to 18
I-18-6 to 8	School Energy Interrogatories 6 to 8
I-25-4 and 7 to 9	VECC Interrogatories 4 and 7 to 9

1.3 Average Use Forecast for Rate Class 6

(Complete Settlement)

There is an agreement to settle this issue (as part of the package) as follows:

> The parties agree, based on the settlement of the Test Year degree day forecast, to a Rate 6 (general service customer) average use forecast of 21,999 m^3. This number was arrived at by applying the Company's regression models referred to in

evidence at A2-2-2, to the gas volume budget and degree day forecast settled in issue 1.1 above.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, OAPPA, Superior and TransAlta.

Approval: All participating parties accept and agree with the proposed settlement of this issue except Union, DEML and ECNG who take no position.

Evidence: The evidence in relation to this issue includes the following:

A2-2-2	Average Use Forecasting Model for Rate 1
A2-2-3	Average Use Forecasting Model for Rate 6
I-1-13, 20 and 21 to 25	Board Staff Interrogatories 13, 20 and 21 to 25
I-8-8 to 10 and 15 to 18	Energy Probe Interrogatories 8 to 10 and 15 to 18
I-18-6 to 8	School Energy Interrogatories 6 to 8
I-25-4 and 7 to 10	VECC Interrogatories 4 and 7 to 10

1.4 Budget Degree Days – Proposal to change to the DeBever With Trend Forecasting Methodololgy

(Complete Settlement)

In view of the settlement of issue 1.1, the parties agree that issue 1.4 does not need to be addressed in this proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, OAPPA, Superior and TransAlta.

Approval: All participating parties accept and agree with the proposed settlement of this issue except Union, DEML and ECNG who take no position.

Evidence: The evidence in relation to this issue includes the following:

A2-2-5	Budget Degree Days
A2-2-5	Budget Degree Days
I-1-27 to 35	Board Staff Interrogatories 27 to 35
I-8-19 to 31	Energy Probe Interrogatories 19 to 31
I-18-9	School Energy Interrogatory 9
I-29-1 to 10	Enbridge Interrogatories of Energy Probe 1to 10
L-8-1	Energy Probe Evidence

2 OTHER REVENUE

2.1 Appropriateness of the forecast of Other Service Revenue

(Complete Settlement)

There is an agreement to settle this issue (as part of the package) as follows:

> For the Test Year, the parties agree to a forecast Revenue from Other Services of $10,650,000. This revenue is a forecast of the Company's charges to customers for services that are not covered by its gas distribution rates. For the Test Year, the Company expects Other Service activity levels to remain relatively the same as that anticipated in the 2005 Estimate. The settlement reflects the forecast of a slight increase in New Account Charge revenue, offset by a decrease in the DPAC revenue. Several parties' agreement on this issue is inseparably linked to the settlement of issue 18.2 (Direct Purchase Administration and System Gas Fees.)

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, OAPPA and TransAlta.

Approval: All participating parties accept and agree with the proposed settlement of this issue except Superior, ECNG and Union who take no position.

Evidence: The evidence in relation to this issue includes the following:

A2-4-1	Other Services Revenue
C1-3-1	Details of Other Revenue 2006 Budget and 2005 Estimate
C2-3-1	Details of Other Revenue 2005 Estimate and 2004 Actual
C2-3-2	Details of Other Revenue 2005 Estimate
C3-3-1	Details of Other Revenue 2004 Actual and 2004 Estimate
I-1-36	Board Staff Interrogatory 36
I-8-33 to 35	Energy Probe Interrogatories 33 to 35
I-18-12	School Energy Interrogatory 12
I-20-1 to 3	Superior Energy Interrogatories 1 to 3
I-25-14	VECC Interrogatory 14

3 TRANSACTIONAL SERVICES

3.1 Gross Margin Forecast (A2/T5/S1)

(No Settlement)

> There is no agreement to settle this issue.

3.2 Proposed new sharing mechanism for Transactional Services for 2006 (A2/T5/S1)

(No Settlement)

There is no agreement to settle this issue.

3.3 Enbridge Gas Services (EGS) and Enbridge Operational Services (EOS) Services Agreements, as they relate to the provision of Transactional Services, to the extent not dealt with in EB-2005-0244

(Complete Settlement)

There is an agreement to settle this issue as follows:

This issue has been resolved in accordance with the Board's final order in EB-2005-0244, except for the cost consequences of these agreements, which fall within the scope of unresolved issue 9.18.

Participating Parties: All parties participated in the negotiation and settlement of this issue except OAPPA, TransAlta and Superior.

Approval: All participating parties accept and agree with the proposed settlement of this issue except, DEML, ECNG, Schools and Union who take no position.

4 CLASS ACTION SUIT DEFERRAL ACCOUNT

4.1 Recovery of amounts (estimated at $1.725 million) in the 2005 Class Action Suit Deferral Account (2005 CASDA) (A2/T6/S1)

(Complete Settlement)

There is an agreement to settle this issue as follows:

As a result of the Supreme Court of Canada's decision of April 22, 2004 in the "Garland" case, the Company is required to repay late payment penalties collected from the plaintiff in excess of the interest limit stipulated in s. 347 of the Criminal Code in a total amount to be determined by the trial judge. The Board has authorized the Company to record in a deferral account the costs which it incurs related to the litigation and the plaintiff's costs. There is an issue pertaining to the extent to which ratepayers and/or the shareholder are responsible for any of these amounts, which the Board in its decision in RP-2003-0203 deferred to a later date.

The Company has forecast that the amounts attributable to the litigation and the plaintiff's costs at December 31, 2005 will be a total of about $1.725 million. Further amounts payable, if any, have yet to be determined by the Court. The parties agree that the Board's determination of ratepayer and/or shareholder responsibility for these amounts should await the Court's determination of amounts payable. The parties agree that no amounts in the 2005 CASDA shall be cleared in the 2006 Test Year but, rather, all amounts recorded in the 2005 CASDA at December 31, 2005 should be transferred to a 2006 Test Year CASDA in which further amounts attributable to the litigation and the judgment, if any, will be recorded.

This disposition of the matter is considered by the parties to be compliant with Section 36(4.2) of the OEB Act, which provides as follows:

> If a gas distributor has a deferral or variance account that does not relate to the commodity of gas, the Board shall, at least once every 12 months, or such shorter period as is prescribed by the regulations, make an order under this section that determines whether and how amounts recorded in the account shall be reflected in rates.

If the Board finds that this disposition of the matter is not compliant with Section 36(4.2) of the OEB Act, then the issue of ratepayer and/or shareholder responsibility for the amounts recorded in the 2005 CASDA will need to be determined at the hearing.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, OAPPA, Superior and TransAlta.

Approval: All participating parties accept and agree with the proposed settlement of this issue except Union, DEML, and ECNG who take no position.

Evidence: The evidence in relation to this issue includes the following:

A2-6-1	Late Payment Penalty Revenue
A8-5-1	Class Action Suit and Late Payment Penalty Revision Deferral Accounts
I-1-42, 142 and 143	Board Staff Interrogatories 42, 142 and 143
I-5-6 to 10 and 51	CCC Interrogatories 6 to 10 and 51
I-8-52 to 54	Energy Probe Interrogatories 52 to 54
I-18-14	School Energy Interrogatory 14

4.2 Request to establish a 2006 CASDA

(Complete Settlement)

There is an agreement to settle this issue as follows:

In accordance with the settlement of issue 4.1, the parties agree to the establishment of a 2006 CASDA. The issue of ratepayer and/or shareholder responsibility for (Court-determined) amounts recorded therein is to be considered by the Board in a future funded proceeding in which all stakeholders can participate.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, OAPPA, Superior and TransAlta.

Approval: All participating parties accept and agree with the proposed settlement of this issue except Union, ECNG which takes no position.

Evidence: The evidence in relation to this issue includes the following:

A2-6-1	Late Payment Penalty Revenue
A8-1-1	Deferral and Variance Accounts Evidence Summary
A8-2-1	Proposed Clearing of the 2005 Deferral and Variance Accounts
A8-5-1	Class Action Suit and Late Payment Penalty Revision Deferral Accounts
I-1-42, 142 and 143	Board Staff Interrogatories 42, 142 and 143
I-5-6 to 10 and 51	CCC Interrogatories 6 to 10 and 51
I-8-52 to 54	Energy Probe Interrogatories 52 to 54
I-18-14	School Energy Interrogatory 14

5 LATE PAYMENT PENALTY

5.1 Compliance with Board's September 30, 2004 directive to switch from a 2% one-time penalty to a 1.5% monthly interest LPP, including the request for a deferral account to capture 2005 implementation costs, and the recovery of those costs in 2006.

(No Settlement)

There is no agreement to settle this issue.

6 GAS COSTS, TRANSPORTATION, AND STORAGE

6.1 Gas, Transportation and Storage costs (A3/T2/S1)

(No Settlement)

There is no agreement to settle this issue.

6.2 2005 implementation of Enbridge Gas DistributionI Gas Supply Risk Management Program Recommendations (A3/T3/S1)

(No Settlement)

There is no agreement to settle this issue.

6.3 2006 implementation plans for Enbridge Gas DistributionI Gas Supply Risk Management Program Recommendations (A3/T3/S1)

(No Settlement)

There is no agreement to settle this issue.

6.4 Implications of, and the report on, Customer Threshold for Gas Supply Volatility Study (A3/T3/S1)

(No Settlement)

There is no agreement to settle this issue.

7 COST OF CAPITAL

7.1 Estimates of the cost and mix of short-term and long-term debt for the 2006 Test Year

(Complete Settlement)

There is an agreement to settle this issue (as part of the package) as follows:

> The cost of *short-term* debt for the 2006 Test Year will be 3.46%.
>
> The cost of *medium* and *long-term* debt for the 2006 Test Year will be 5.15% for the 10-year bond and 5.87% for the 30-year bond, which the Company plans to issue in July and January of the Test Year, respectively.
>
> These rates (listed in Appendix “A”, attached) are based on an average of the interest rate forecasts provided by the five major Canadian chartered banks and, in the case of the medium and long-term debt rates, the corporate spreads and debt issuance costs actually incurred by the Company in the Bridge Year.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, OAPPA, Superior and TransAlta.

Approval: All participating parties accept and agree with the proposed settlement of this issue except DEML, ECNG and Union who take no position.

Evidence: The evidence in relation to this issue includes the following:

A4-2-1	Cost of Capital
A4-2-3	Capital Market and Economic Assumption Analysis
I-1-57 and 58	Board Staff Interrogatories 57 and 58
I-3-9 and 10	CME Interrogatories 9 and 10
I-8-36 to 40	Energy Probe Interrogatories 37 to 38
I-11-28 to 30	IGUA Interrogatories 28 to 30
I-18-24	School Energy Interrogatory 24
I-25-37	VECC Interrogatory 37

7.2 Determination of calendar ROE for the 2006 Test Year using the Board's Guidelines

(Complete Settlement)

There is an agreement to settle this issue (as part of the package) as follows:

The parties agree that the Board's guidelines for determining Enbridge's ROE for the 2006 Test Year should be applied as follows:

* ROE for the 2005 Test Year is 9.57%

* The 30 year long Canada forecast used for the 2005 Test Year is 5.81%

* The long Canada forecast for the 2006 Test Year based on the most recent Company forecast is 5.616% (This placeholder will be replaced with the 2006 long Canada forecast contained in the October issue of the *Consensus Forecasts* (being the most recent forecast that can be incorporated for rate-making purposes as at December 31, 2005) as prescribed by the Board's ROE guidelines

* The difference between the two long Canada forecasts is a line difference of -19.4 basis points

* The adjustment factor is 75% of the difference, which is -0.145%

Pending availability of the October 2005 Consensus Forecasts, the interim calculation of ROE is therefore 9.567% less 0.145%, which equals 9.422%, rounded to 9.42%.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, OAPPA, Superior and TransAlta.

Approval: All participating parties accept and agree with the proposed settlement of this issue except DEML, ECNG and Union who take no position.

Evidence: The evidence in relation to this issue includes the following:

A4-1-1	Cost of Capital Evidence Summary
A4-2-1	Cost of Capital
A4-2-2	ROE Calculations
I-1-59	Board Staff Interrogatory 59
I-3-10	CME Interrogatory 10
I-8-41 to 44	Energy Probe Interrogatories 41 to 44
I-11-31	IGUA Interrogatory 31
I-18-25	School Energy Interrogatory 35
I-25-13 and 34	VECC Interrogatories 13 and 34

7.3 Appropriateness of including any standby credit fees in the Cost of Capital, and in the alternative, the amount thereof.

(Complete Settlement)

There is an agreement to settle this issue as follows:

The intervenors have agreed to refrain from taking issue with the Company's evidence in this proceeding regarding the standby credit fees. Accordingly, the costs of the standby credit fees of $960,000 per annum for the $800 million revolving bank credit facility required to backstop the Company's commercial paper program are no longer in dispute for the 2006 Test Year.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, OAPPA, Superior and TransAlta.

Approval: All participating parties accept and agree with the proposed settlement of this issue except DEML, ECNG, VECC, CME and Union who take no position.

Evidence: The evidence in relation to this issue includes the following:

A4-2-1	Cost of Capital
I-1-58	Board Staff Interrogatory
I-8-45	Energy Probe Interrogatory 45
I-11-28	IGUA Interrogatory 28

I-18-24	School Energy Interrogatory 24
L-11-1	IGUA Evidence

8 RATE BASE

8.1 Capital Budget for the 2006 Test Year including capitalized O&M expenses (A5/T1-2/S1)

(No Settlement)

There is no agreement to settle this issue.

8.2 Information Technology Capital Budget including Energy Transaction, Reporting, Accounting and Contracting (EnTrac), and Meter Management and Large Volume Meter Data Processing (EnMar) projects (A5/T4/S1)

(No Settlement)

There is no agreement to settle this issue.

8.3 Appropriateness of the capital budget "placeholder" for power generation project RFPs (A5/T2/S1)

(No Settlement)

There is no agreement to settle this issue.

8.4 Appropriateness of the capital budget for System Improvements and Upgrades, including the budget increases in system expansion and reinforcement projects and the Accelerated Bare Steel and Cast Iron Replacement Program (A5/T2/S1)

(No Settlement)

There is no agreement to settle this issue.

9 2006 OPERATIONS AND MAINTENANCE BUDGET

(No Settlement)

There is no agreement to settle any of the 2006 O&M Budget-related series of issues.

9.1 Overall O&M levels for 2006 (A6/T1/S1)

9.2 O&M - Finance (A6/T2/S1)

9.3 O&M - Customer Support (A6/T2/S2)

9.4 O&M - Customer Care - Customer Works Limited Partnership & Enbridge Commercial Services Segmented Financial Statements (A6/T2/S3)

9.5 O&M - CIS Replacement (A6/T2/S4)

9.6 O&M – Customer Care Cost Update (A6/T2/S5)

9.7 O&M - Engineering Department (A6/T3/S1)

9.8 O&M - Opportunity Development, including electricity to gas fuel switching activities (A6/T4/S1)

9.9 O&M - Natural Gas for Vehicles (NGV) (A6/T4/S2)

9.10 O&M - Gas Storage Operations (A6/T4/S3)

9.11 O&M - Regional Operations (A6/T5/S1)

9.12 O&M - Strategic and Key Accounts (A6/T5/S5)

9.13 O&M - Human Resources (A6/T6/S1)

9.14 O&M - Legal, Regulatory and Public Affairs (A6/T7/S1-5)

9.15 O&M - Information Technology Department (A6/T8/S1)

9.16 Non-Departmental O&M Expenses (A6/T9/S1)

9.17 Corporate Cost Allocations including Deloitte Evaluative Report

9.18 O&M Affiliate Transactions and Non-Utility Elimination (A6/T10/S1)

9.19 Third party access to customer bills (excluding ABC-T billing service) including its revenue and cost impacts

10 NATURAL GAS VEHICLES

10.1 Review of NGV program (A6/T4/S2)

(Partial Settlement)

There is a partial settlement of this issue (as a part of the package) as follows:

> The parties, except for Schools, agree that revenue in the amount of $559,000 will be imputed to the NGV program for the Test Year.
>
> Schools agrees with a reduction in revenue requirement of $559,000, but opposes imputing revenues to the NGV program. The parties agree that, if Schools pursues the attribution issue at the hearing of this case and is successful, the Company will not impute revenues to the NGV program, but will still reduce its revenue requirement by $559,000, through an adjustment to another revenue or expense item of that magnitude.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, OAPPA, Superior and TransAlta.

Approval: All participating parties accept and agree with the proposed settlement of this issue except Schools, for the reasons cited above, and Union, ECNG and DEML who take no position.

Evidence: The evidence in relation to this issue includes the following:

A6-4-2	Natural Gas for Vehicles ("NGV")
C1-4-1	NGV Program Performance 2006
C2-4-1	NGV Program Performance 2005
C3-4-1	NGV Program Performance 2004
I-1-107, 127 and 128	Board Staff Interrogatories 107, 127 and 128
I-5-48, 49 and 121	CCC Interrogatories 48, 49 and 121
I-8-87 and 88	Energy Probe Interrogatories 87 and 88
I-11-22	IGUA Interrogatory 22
I-38-1 to 3	Energy Probe Interrogatories of CNGVA 1 to 3
L-4-1	CNGVA Evidence

11 ENVISION PROJECT

11.1 EnVision Project including HLB Decision Economics Inc. Interim Final Opinion: Review of EnVision Benefits Realization Plan and Contract (A6/T5/S1-4)

(No Settlement)

There is no agreement to settle this issue. The parties have, however, prepared the following in an attempt to scope the unresolved issue(s) for the Board.

In the RP-2003-0203 Settlement Proposal the EnVision issue was settled subject to the following agreement:

> "Intervenors accept that the EnVision Project is prudent because the Company has justified the need to replace its existing legacy systems and improve upon its overall work management processes. Some Intervenors remain concerned about the EnVision Project's overall projected costs and benefits. In the Intervenors' view, the evidence filed to date has not been sufficient to determine whether the ongoing costs and benefits are reasonable. The Company does not agree. While the Company appreciates the Intervenor's position that the benefits of EnVision should be assessed after there has been actual experience, the Company believes that in this case it has provided sufficient evidence regarding the costs of the project.
>
> Given the multi-year nature of the project it will be necessary for Enbridge Gas Distribution to bring the projected costs and benefits forward in each rate proceeding. Accordingly, parties see the value in and the need for an independent assessment of the project. Parties accept the projected costs and benefits for the Test Year subject to the following conditions:
>
> 1. The Company will retain an independent consultant to assess the overall project costs to determine whether the fee levels and fee structure with Accenture are appropriate relative to the services and value being provided. In the context of this review the consultant will benchmark the services and costs described in the Services Agreement between Enbridge Gas Distribution Inc. and Accenture Inc. against the market. The consultant will also be asked to assess the Benefits Realization Plan and the Gain Sharing Agreement between Accenture and the Company. The terms of reference for the consultant's review will be developed jointly with intervenors. The results of the review will be provided in Enbridge Gas Distribution's next rate proceeding.
>
> 2. Given the concern expressed by intervenors regarding the language in the Services Agreement with Accenture dealing with the possible use by Accenture of Work Product created for Enbridge Gas Distribution to provide services to third parties, and the intellectual property rights in "Work Product", Enbridge Gas Distribution will obtain, from Accenture, a clarification in writing of its interpretation of Clause 8.2 of the Agreement. Specifically, Accenture will confirm that the jointly owned application software to provide the required functionality

for Enbridge Gas Distribution is to be used by Accenture exclusively for Enbridge Gas Distribution. In addition Enbridge Gas Distribution confirms that Enbridge Inc., other than Enbridge Gas Distribution, will not profit directly or indirectly from the Accenture joint ownership of the Work Product. Given the joint ownership of the Work Product by Accenture and Enbridge Gas Distribution, other Enbridge-owned entities will not be precluded from using it. With regard to use of the Work Product by affiliates, Enbridge Gas Distribution recognizes that it is bound by the *Affiliate Relationships Code for Gas Utilities* and will comply with the Code where applicable.

3. Intervenors expressed a concern that although there is a penalty/incentive mechanism applied on an annual basis the only remedy for three consecutive months of missing critical service measures is termination of the Services Agreement. In order to address this concern the Company will commit that, in addition to any other remedies under the Services Agreement, in the event Accenture misses the critical service measures for two consecutive months, Accenture will be put on notice by the Company that Enbridge Gas Distribution will require a 5% discount of the annual fees in addition to the right to terminate if the unacceptable performance continues for a third month.

4. Acceptance of the costs and benefits for the test year will not prejudice the ability of parties to challenge the costs and benefits projections of the EnVision Project in future proceedings."

In response to the conditions set out in the Settlement Agreement Enbridge Gas Distribution retained HLB Decision Economics Inc. ("HLB") to perform both the benchmark and assessment of the Benefits Realization Plan. Parties agree that Enbridge Gas Distribution has complied with its commitment to retain a consultant to review the Benefits Realization Plan and the Gain Sharing Agreement between Accenture and the Company. Enbridge Gas Distribution has committed to redevelop several aspects of the Benefits Realization Plan and Gain Sharing Agreement as recommended by HLB. In addition, Enbridge Gas Distribution has committed to update its EnVision business case to reflect the current project realities. Enbridge Gas Distribution will file its response to the HLB recommendations by December 1, 2005 for review in its next rate proceeding.

With respect to the commitment made by Enbridge Gas Distribution to retain an independent consultant to benchmark the services and costs described in the Services Agreement between Enbridge Gas Distribution and Accenture some parties take the position that Enbridge Gas Distribution has not complied with that commitment. Enbridge Gas Distribution takes the position that it has complied with the Agreement. There is no agreement to settle this component of the EnVision issue.

12 ENTRAC (ENERGY TRANSACTION, REPORTING, ACCOUNTING AND CONTRACTING)

12.1 EnTrac Master Service Agreements (User Agreement, Gas Delivery Agreement, etc.), including the appropriateness of the terms and conditions for access to EnTrac.

(Complete Settlement)

There is an agreement to settle this issue as follows:

The parties agree that the hearing of this issue is not required by the Board in this proceeding, given the following:

Some intervenors have expressed concerns over the appropriateness of certain terms and conditions within the EnTrac Master Service Agreements (namely the EnTRAC User Agreement, Gas Delivery Agreement, Large Volume Distribution Agreement and, to a limited degree, the Collection Services Agreement) relating to "access to EnTrac". In addition, intervenors expressed concerns regarding the restriction of access to EnTRAC to only those entities that had agreed to the original terms and conditions imposed by Enbridge Gas Distribution. Over the course of this proceeding, together with Enbridge Gas Distribution, these intervenors and other additional parties have been involved in a number of meetings and discussions with a view to resolving the concerns, and have reached substantive agreement on issues relating to:

- reciprocal indemnities;
- limitations on liability;
- an expansion of the intellectual property indemnity;
- notification regarding changes to the Transaction Rules;
- confidentiality; and
- events of default and termination,

that the parties understand will be implemented promptly.

While there remain some issues that still require attention and the revised terms and conditions require further review to reach final agreement, the parties are confident that continued negotiations will lead to a resolution of the outstanding concerns that will be agreeable to all parties having expressed an interest in this issue. Enbridge Gas Distribution agrees that the settled terms and conditions will apply uniformly to all EnTRAC users, including those parties that were required to sign the original EnTRAC User Agreement in order to gain access to EnTRAC.

Participating Parties: DEML, HVAC, J.Stacey, OESC, OAPPA, WPS Energy Services of Canada Corp., one of the members of the Advocates for Fair and Non-Discriminatory Access group (Coral Energy Canada Inc. and Cargill Power & Gas Markets, the other two members, did not participate and take no position on this issue), IGUA and Enbridge Gas Distribution participated in the negotiation and settlement of this issue.

Approval: All participating parties accept and agree with the proposed settlement of this issue, without prejudice to the positions that any party may wish to take regarding review of the EnTrac Master Service Agreements as part of the Board's ongoing GDAR proceeding.

Evidence: The evidence in relation to this issue includes the following:

The versions of the EnTRAC User Agreement, Gas Delivery Agreement, Large Volume Distribution Contract and Collection Services Agreement filed by Enbridge in response to IGUA interrogatory #88.

I-11-37, 48, 87, 88	IGUA Interrogatories
I-12-1	J.Stacey Interrogatories
I-14-1, 2, 4	OAPPA Interrogatories
Exhibit J33.7	To provide costs of functionalizing what exists in EnTRAC.

12 ENTRAC (ENERGY TRANSACTION, REPORTING, ACCOUNTING AND CONTRACTING)

12.1 EnTrac Master Service Agreements (User Agreement, Gas Delivery Agreement, etc.), including the appropriateness of the terms and conditions for access to EnTrac.

(No Settlement)

There is no agreement to settle this issue.

13 GAS DISTRIBUTION ACCESS RULE

13.1 Impact of the Gas Distribution Access Rule on Capital and Operating plans and expenditures

(No Settlement)

There is no agreement to settle this issue.

14 TAXES

14.1 Derivation of Income, Large Corporation, Capital and Municipal Property Tax amounts (D1/T1/S1)

(Complete Settlement)

There is an agreement to settle this issue (as part of the package) as follows:

> For the purposes of settlement, the Company agrees to a $1,600,000 reduction in forecast Municipal Property Taxes in the Test Year which reduces the forecast to $36,600,000. The intervenors do not take issue with the Company's evidence in this proceeding with respect to the derivation of income, large corporation and capital taxes.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, OAPPA, Superior and TransAlta.

Approval: All participating parties accept and agree with the proposed settlement of this issue except Union, ECNG and DEML who take no position.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Cost of Service 2006 Test Year
I-1-134	Board Staff Interrogatory 134
I-8-47 to 51	Energy Probe Interrogatories 47 to 51
I-11-80 to 82	IGUA Interrogatories 80 to 82

15 DEMAND SIDE MANAGEMENT (DSM)

15.1 Proposal for a 3 year term (2006-2008) DSM Plan, including the O&M budgets and the volume targets (A7/T2/S1)

(No Settlement)

There is no agreement to settle this issue.

15.2 Attribution of benefits in jointly delivered DSM programs (A7/T4/S1)

(No Settlement)

There is no agreement to settle this issue.

15.3 Proposal to change Demand Side Management Variance Account mechanics (A7/T4/S1)

(No Settlement)

There is no agreement to settle this issue.

15.4 Market Transformation Programs and Incentives (A7/T4/S1)

(No Settlement)

There is no agreement to settle this issue.

15.5 Proposed Shared Savings Mechanism (SSM) incentive model for 2006 (A7/T4/S1)

(No Settlement)

There is no agreement to settle this issue.

15.6 Recovery of SSM and Lost Revenue Adjustment Mechanism (LRAM,) amounts for 2003 (A8/T3/S1)

(Complete Settlement)

As identified in the August 10, 2005 Settlement Agreement, the parties agreed that the disposition of the 2003 SSM and 2003 LRAM balances should be deferred until after the Audit Subcommittee and DSM Consultative have completed their review and provided their recommendations. This process has now been completed, and there is agreement to settle the issue as follows:

The parties agree that the 2003 SSM of $2,635,292 to the Company and LRAM of $502,333 to ratepayers should be cleared as recommended by the Audit Subcommittee.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, DEML, ECNG, OAPPA, OESC, Superior, TransAlta, TEC, and TransCanada.

Approval: All participating parties accept and agree with the proposed settlement of this issue except CME which takes no position.

Evidence: The evidence in relation to this issue includes the following:

I-1-4	Board Staff Interrogatory 4
I-5-63	CCC Interrogatory 63
I-11-72	IGUA Interrogatory 72
Exhibit K27.1	Kai Millyard Associates Memo August 5, 2005
Exhibit K27.2	F2003 DSM Audit SSM Replication Report, dated August 4, 2005
Exhibit K27.3	ECONorthwest Audit Report on Enbridge Gas Distribution 2003 DSM Evaluation, dated July 26, 2005
Exhibit K30.1	2003 Post Audit LRAM Calculation Table

15.6 Recovery of SSM and Lost Revenue Adjustment Mechanism (LRAM) amounts for 2002 and 2003 (A8/T3/S1)

(Complete Settlement)

There is an agreement to settle this issue as follows:

The parties agree that the 2002 SSM of $1,795,807 to the Company and 2002 LRAM of $894,480 to ratepayers should be cleared as recommended by the Audit Subcommittee.

The parties agree that the disposition of the 2003 SSM and 2003 LRAM balances should be deferred until after the Audit Subcommittee and DSM Consultative have completed their review and provided their recommendations.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, OAPPA, Superior and TransAlta.

Approval: All participating parties accept and agree with the proposed settlement of this issue except DEML, ECNG, Union and CME who take no position.

Evidence: The evidence in relation to this issue includes the following:

A7-11-1	DSM Audit Report – 2002
I-1-4	Board Staff Interrogatory 4
I-5-63	CCC Interrogatory 63
I-11-72	IGUA Interrogatory 72
I-18-50	School Energy Interrogatory 50

15.7 Recovery of DSMVA for 2002 and 2003 (A8/T3/S1)

(No Settlement)

There no agreement to settle this issue.

16 DEFERRAL AND VARIANCE ACCOUNTS

16.1 Amounts and proposed disposition of balances in historic deferral and variance accounts (A8/T2/S1and A8/T3/S1)

(Complete Settlement, subject to exceptions noted below)

With the exception of the 2005 Ontario Hearing Costs Variance Account (“2005 OHCVA”), the 2005 Transactional Services Deferral Account (“2005 TSDA”) and the 2005 Late

Payment Penalty Revision Deferral Account ("2005 LPPRDA"), there is an agreement to settle this issue as follows:

> The Company filed a summary of the deferral and variance accounts it proposed to clear at Exhibit A8, Tab 2, Schedule 1, (actual account balances as at January 31, 2005) and an update of the balances as at April 30, 2005 in response to Board Staff Interrogatory #143. The balances recorded and proposed for clearance in the following deferral and variance accounts established pursuant to the RP-2003-0203 Rate Order are accepted by the parties for the reasons given in the supporting evidence, and in this Settlement Proposal:
>
> **Gas Supply Related Deferral Accounts**
>
> 2005 Union Gas Deferral Account ("2005 UGDA")
> 2005 Unaccounted for Gas Variance Account ("2005 UAFVA") and
> 2005 Transactional Services Deferral Account ("2005 TSDA") *
>
> **Non-Gas Supply Related Deferral Accounts**
>
> 2002 Lost Revenue Adjustment Mechanism Variance Account ("2002 LRAM")
> 2002 Shared Saving Mechanism Variance Account ("2002 SSMVA")
> 2005 Debt Redemption Deferral Account ("2005 DRDA")
> 2005 Deferred Rebate Account ("2005 DRA")
> 2005 Customer Communication Plan Deferral Account ("2005 CCPDA")
> 2005 Corporate Cost Allocation Methodology Deferral Account ("2005 CCAMDA")
> 2005 Gas Supply Risk Management Program Deferral Account ("2005 GSRMPDA")
> 2005 Storage Rights Compensation Costs Deferral Account ("2005 SRCCDA")
> 2005 Ontario Hearing Costs Variance Account ("2005 OHCVA") [*]
>
> The parties' agreement to clear the amounts recorded in the 2002 SSMVA and the 2002 LRAM is discussed at issue 15.6.

The Company will clear the actual principal balances accumulated as at September 30, 2005 in the accounts listed above plus related interest, commencing January 1, 2006. If the actual principal balance in any account varies more than $100,000 from the amount set forth for that account in Appendix B, the Company will provide an explanation to the Board and to intervenors no later than November 15, 2005, so that parties will have an opportunity to make submissions with respect thereto if appropriate. Amounts accumulated in these accounts in the months of October through December of 2005 will be recorded along with appropriate interest to be brought forward in a future proceeding for review and disposition by the Board.

> The Company does not seek to clear, in the Test Year, the balances recorded in the following Non-Gas Supply Variance Accounts:

[*] Subject to exceptions as noted below.

2004 Demand Side Management Variance Account (“2004 DSMVA-Operating”)
2004 Shared Saving Mechanism Variance Account (“2004 SSMVA”)
2004 Lost Revenue Adjustment Mechanism Variance Account (“2004 LRAM”)
2005 Demand Side Management Variance Account (“2005 DSMVA-Operating”)
2005 Shared Saving Mechanism Variance Account (“2005 SSMVA”)
2005 Lost Revenue Adjustment Mechanism Variance Account (“2005 LRAM”)

The disposition of the 2003 SSMVA and the 2003 LRAM are discussed at issue 15.6. The Company will provide the post audit amounts and request disposition of these amounts if they become available during the hearing. In accordance with issue 15.7, there is no settlement with respect to recovery of amounts recorded in the 2002 and 2003 DSMVA, and so parties will address the disposition of these accounts at the hearing.

In accordance with the settlement of issue 4.1, the Company will not clear the amounts recorded in the 2005 CASDA in the Test Year.

The parties agree that the disposition of the amounts recorded in the 2005 Gas Distribution Access Rule Costs Deferral Account (“2005 GDARCDA”) should be deferred until after the Board has provided guidance with respect to the allocation of GDAR costs.

The Company will dispose of amounts recorded in the 2005 Purchased Gas Variance Account (“2005 PGVA”) in accordance with the Board’s prescribed quarterly rate adjustment mechanism process.

The parties have agreed to eliminate the requirement of a 2005 Notional Utility Account Deferral Account (“2005 NUADA”) in accordance with the settlement of issue 16.3.

The disposition of this matter is considered by the parties to be compliant with Section 36(4.2) of the OEB Act. If the Board finds that this is not the case, then the disposition of those accounts that the Board considers to be non-compliant with Section 36(4.2) of the OEB Act shall be determined at the hearing.

Exceptions:

There is no agreement to settle the disposition and/or other aspects of the following accounts, however, the parties propose the following wording to scope the issue(s) for the Board:

2005 OHCVA: The questions to be determined by the Board are whether the appeal costs and re-hearing costs, if any, related to the Alliance/Vector remand proceeding are properly recorded in the 2005 OHCVA and ultimately, the appropriate disposition of those costs. Pending resolution of those questions by the Board, the Company will not clear any of the costs recorded in the 2005 OHCVA that relate to Alliance/Vector but will clear the balance of the amounts recorded.

2005 LPPRDA: The establishment of a 2005 LPPRDA is an issue in this proceeding and the subject of an accounting order application currently before the Board. The parties agree that if the Board approves the establishment of the 2005 LPPRDA, then the costs to be recorded therein, and disposed of, should be determined as an element of the Decision in this case.

2005 TSDA: Intervenors are waiting for a response from the Company relating to entries made to this account for any transaction “unwinding costs”. The allocation of responsibility for unwinding costs may become an issue if the amounts are material.

Participating Parties: All parties participated in the negotiation and settlement of this issue except TransAlta, OAPPA and Superior. Advocates participated with respect to the TSDA only.

Approval: All participating parties accept and agree with the proposed settlement of this issue except Union, CME, Advocates, and DEML who take no position.

Evidence: The evidence in relation to this issue includes the following:

A8-2-1	Proposed Clearing of the 2005 Deferral and Variance Accounts
A8-3-1	Balances of Fiscal 2005 Deferral and Variance Accounts
A8-5-1	Class Action Suit and LPP Revision Deferral Accounts
A9-1-3	Change in Fiscal Year End Revenue Requirement Impact
I-1-142 and 143	Board Staff Interrogatories 142 and 143
I-8-52 to 55	Energy Probe Interrogatories 52 to 55
I-16-110,111	School Interrogatories 110, 111

16.2 Request to continue or establish new deferral and variance accounts for 2006 (A8/T1/S1)

(Complete Settlement, subject to exceptions noted below)

There is an agreement to settle this issue as follows:

Enbridge Gas Distribution’s proposal to establish the following deferral and variance accounts for the Test Year, including the accounting methodology, is accepted by the parties for the reasons given in the supporting evidence:

2006 Purchased Gas Variance Account (“2006 PGVA”)
2006 Unaccounted for Gas Variance Account (“2006 UAFVA”)

2006 Union Gas Deferral Account ("2006 UGDA")
2006 Debt Redemption Deferral Account ("2006 DRDA")
2006 Deferred Rebate Account ("2006 DRA")
2006 Gas Distribution Access Rule Costs Deferral Account ("2006 GDARCDA")
2006 Ontario Hearing Costs Variance Account ("2006 OHCVA")
2006 Class Action Suit Deferral Account ("2006 CASDA")

See issue 4.2 for the parties' settlement in relation to the 2006 CASDA.

The Company is requesting establishment of the following Demand Side Management Variance Accounts but the mechanics of the various accounts will be addressed at the hearing:

2006 Demand Side Management Variance Account ("2006 DSMVA-Operating")
2006 Shared Saving Mechanism Variance Account ("2006 SSMVA")
2006 Lost Revenue Adjustment Mechanism Variance Account ("2006 LRAM")

In accordance with the settlement of issue 16.3, the Company has agreed to withdraw its request for a 2006 Notional Utility Account Deferral Account.

Exceptions

There is no agreement to settle the following accounts for which the Company has requested approval in the 2006 Test Year:

2006 Customer Communication Plan Deferral Account ("2006 CCPDA")
2006 Corporate Cost Allocation Methodology Deferral Account ("2006 CCAMDA")

In accordance with issue 16.4, there is no agreement to establish a 2006 Manufactured Gas Plant Variance Account ("2006 MGPDA"). Further, the parties agree that the establishment of a 2006 Transactional Services Deferral Account ("2006 TSDA") will be addressed at the hearing, in relation to issues 3.1 and 3.2.

Participating Parties: All parties participated in the negotiation and settlement of this issue except OAPPA, Superior, and TransAlta. Advocates participated with respect to the TSDA only.

Approval: All participating parties accept and agree with the proposed settlement of this issue except Union, CME, Advocates and DEML who take no position.

Evidence: The evidence in relation to this issue includes the following:

A2-5-1	Transactional Services
A8-1-1	Deferral and Variance Accounts Evidence Summary
A8-4-1	Manufactured Gas Plant Variance Account
I-1-146	Board Staff Interrogatory 146
I-5-62	CCC Interrogatory 62

I-8-56 to 58	Energy Probe Interrogatories 56 to 68
I-11-83	IGUA Interrogatory 83

16.3 Request to establish a 2006 Notional Utility Account Deferral Account (A8/T1/S1)

(Complete Settlement)

There is an agreement to settle this issue as follows:

> The parties have agreed that the Company will continue to recover in rates in the 2006 and 2007 Test Years the appropriate Notional Utility Account amounts to be recovered in order to amortize the full amounts payable by ratepayers in 2005, 2006, and 2007 (in accordance with the Board's decision in RP-2003-0203). This Agreement operates to increase the delivery related revenue deficiency as originally applied for by $12.3 million. On the basis of this Agreement, the Company withdraws its request to establish a 2006 Notional Utility Deferral Account.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, OAPPA, Superior and TransAlta.

Approval: All participating parties accept and agree with the proposed settlement of this issue except Union, DEML, and ECNG who take no position.

Evidence: The evidence in relation to this issue includes the following:

A8-1-1	Deferral and Variance Accounts Evidence Summary
I-1-146	Board Staff Interrogatory 146
I-8-58	Energy Probe Interrogatory 58

16.4 Request to establish a 2006 Manufactured Gas Plant Variance Account (A8/T4/S1)

(No Settlement)

There is no agreement to settle this issue.

17 COST ALLOCATION

17.1 2006 Cost Allocation (G1/T1/S1)

(Complete Settlement)

There is an agreement to settle this issue as follows:

> Subject to the settlement of issue 18.2 below, intervenors do not take issue with the Company's evidence in this proceeding regarding 2006 Cost Allocation.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates and OAPPA.

Approval: All participating parties accept and agree with the proposed settlement of this issue except Superior, TransAlta, ECNG and Union who take no position.

Evidence: The evidence in relation to this issue includes the following:

G1-1-1	Cost Allocation
G2-3-1	Functionalization of Utility Rate Base
G2-3-2	Functionalization of Utility Working Capital
G2-3-3	Functionalization of Utility Net Investments
G2-3-4	Functionalization of Utility O&M
G2-4-1	Classification of Rate Base
G2-4-2	Classification of Net Investment Costs
G2-4-3	Classification of O&M Costs
G2-5-1	Allocation of Rate Base 2006 Test Year
G2-5-2	Allocation of Return & Taxes 2006 Test Year
G2-5-3	Allocation of Total Cost of Service 2006 Test Year
G2-6-1	Rate Base Functionalization Factors
G2-6-2	Classification of Gas Costs to Operations
G2-6-3	Allocation Factors
G2-6-4	Allocation of DSM Program Costs
G2-7-1	Tecumseh - Functionalization and Classification of Rate Base
G2-7-2	Tecumseh - Functional Allocation of Cost of Service
G2-7-3	Tecumseh - Classification of Cost of Service
G2-7-4	Tecumseh - Rate Derivation 2006 Test Year
G2-7-5	Tecumseh - Isolation of Transmission Related Rate Base 2006 Test Year
G2-7-6	Tecumseh - Isolation of Transmission Related Cost of Service 2006 Test Year
G2-7-7	Functionalization of Short Cycle Net Revenues to In/Ex Franchise Customers 2006 Test Year
I-1-147	Board Staff Interrogatory 147
I-18-53 and 54	School Energy Interrogatories 53 and 54
I-25-74	VECC Interrogatory 74

17.2 Changes in revenue to cost ratios (G2/T2/S1)

(Complete Settlement)

There is an agreement to settle this issue as follows:

> Subject to the settlement of issue 18.2 below, intervenors do not take issue with the Company's evidence in this proceeding regarding changes in revenue to cost ratios.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates and OAPPA.

Approval: All participating parties accept and agree with the proposed settlement of this issue except Superior, TransAlta, ECNG and Union who take no position.

Evidence: The evidence in relation to this issue includes the following:

G2-1-1	Fully Allocated Cost - Existing Methodology
G2-2-1	Revenue to Cost/Rate of Return Comparisons
G2-2-2	Revenue to Cost/Rate of Return Comparisons Excluding Gas Supply Commodity
I-8-64 and 65	Energy Probe Interrogatories 64 and 65
I-25-73 and 77	VECC Interrogatories 73 and 77

18 RATE DESIGN

18.1 Proposal for changes to the Rate Handbook (H1/T1/S1 & H2/T6/S1)

(Complete Settlement)

There is an agreement to settle this issue as follows:

Subject to the settlement of issue 18.2 below, intervenors do not take issue with the Company's evidence in this proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates and OAPPA.

Approval: All participating parties accept and agree with the proposed settlement of this issue except DEML, TransAlta, ECNG and Union who take no position.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	Rate Design
H2-6-1	Rate Handbook
I-8-67 and 72	Energy Probe Interrogatories 67 and 72
I-25-79, 80 and 85	VECC Interrogatories 79, 80 and 85

18.2 Direct Purchase Administration Charge and System Gas fees (H1/T1/S1 & H2/T6/S1)

(Complete Settlement)

There is agreement to settle this issue as follows:

The Company agrees to maintain for 2006 both: (i) the current structure, level and administration of the system gas fee and direct purchase administration charge ("DPAC"); and (ii) the Board approved costs allocated to such fees in 2005 (i.e. $

0.88 million to system gas and $1.56 million to DPAC) on the understanding that the Board will be examining the costing of such fees on a fully allocated or incremental basis in the context of its pending Natural Gas Forum generic proceeding on Cost Allocation of Regulated Gas Supply expected to be held in 2006.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, OAPPA, and TransAlta.

Approval: All participating parties accept and agree with the proposed settlement of this issue except ECNG and Union who take no position.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	Rate Design
H2-6-1	Rate Handbook
I-8-62, 63 and 68 to 70	Energy Probe Interrogatories 62, 63 and 68 to 70
I-18-56 and 58	School Energy Interrogatories 56 and 58
I-20-10 to 12	Superior Energy Interrogatories 10 to 12
I-25-70 to 72	VECC Interrogatories 70 to 72, 81 and 82

18.3 Timing and changes to all aspects of Enbridge Gas Distribution's Rate 300, 305, 310 & 315 rate schedules

(No Settlement)

There is no agreement to settle this issue.

18.4 2006 Revenue Deficiency allocation

(Complete Settlement)

There is an agreement to settle this issue as follows:

Intervenors do not take issue with the Company's evidence in this proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, OAPPA and Superior.

Approval: All participating parties accept and agree with the proposed settlement of this issue except DEML, Union, ECNG, VECC and TransAlta who take no position.

Evidence: The evidence in relation to this issue includes the following:

H2-1-1	Revenue Comparison - Current vs Proposed by Rate Class & Component - Existing Methodology
H2-1-2	Proposed Volumes and Revenue Recovery by Rate Class
I-8-73 and 75	Energy Probe Interrogatories 73 and 75
I-18-57	School Energy Interrogatory 57
I-25-75 to 77	VECC Interrogatories 75 to 77

18.5 Review of the rate impacts including Year 2 phase-in of Cost Allocation changes and material changes, if any, from RP-2003-0203 Settlement Proposal (Ref: clause 15.4)

(Complete Settlement)

There is an agreement to settle this issue as follows:

Intervenors do not take issue with the Company's evidence in this proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates, Superior and DEML.

Approval: All participating parties accept and agree with the proposed settlement of this issue except Union, ECNG and TransAlta who take no position.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	Rate Design
I-8-74	Energy Probe Interrogatory 74
I-22-1 to 9	TransAlta Interrogatories 1 to 9
I-25-84	VECC Interrogatory 84

19 RATE IMPLEMENTATION

19.1 Year 2 phase-in of cost allocation changes for upstream transportation, storage, peaking service and interruptible credits (H1/T1/S1 & H2/T4/S1)

(Complete Settlement)

There is an agreement to settle this issue as follows:

Intervenors do not take issue with the Company's evidence in this proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates and Superior.

Approval: All participating parties accept and agree with the proposed settlement of this issue except DEML, ECNG, Union and TransAlta who take no position.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	Rate Design
H2-4-1	Calculation of Gas Supply Charges by Rate Class
I-22-2 to 9	TransAlta Interrogatories 2 to 9

19.2 Implementation of any other rate design changes (H1/T1/S1)

(Complete Settlement)

There is an agreement to settle this issue as follows:

> Intervenors do not take issue with the Company's evidence in this proceeding.

Participating Parties: All parties participated in the negotiation and settlement of this issue except Advocates and OAPPA.

Approval: All participating parties accept and agree with the proposed settlement of this issue except DEML, Superior, TransAlta, ECNG, VECC and Union who take no position.

Evidence: The evidence in relation to this issue includes the following:

H1-1-1	Rate Design

19.3 Timing of implementation of 2006 rates

(No Settlement)

There is no agreement to settle this issue. However, the question that the intervenors wish the Board to consider is the following:

> In the event that the Board's order in this case includes a rate increase, and the Company is unable to implement that increase at the beginning of the Test Year, should the portion of the deficiency that would have been recovered in the period from January 1, 2006 to the date of implementation be recovered by the Company?

Interest Rate Forecast (Issue 7.1) – Appendix A

90 Day	2006 1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	
BMO	3.35	3.65	3.7	3.65	3.75
RBC	3.25	3.5	3.75	3.75	3.72
Scotia	2.75	2.75	2.75	2.75	2.91
Average					**3.46**

10 year	2006 1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	
BMO		4.15	4.2		4.18
RBC		4.75			4.75
Scotia		4.2			4.20
Average					**4.38**

30 year	2006 1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	
BMO	n/a				
RBC	4.7				4.70
Scotia	4.45				4.45
Average					**4.58**

	Interest Rate	Corporate Spread	Issuance Cost	
All in cost				
90 day	3.46			**3.46**
10 year	4.38	0.7	0.07	**5.15**
30 year	4.58	1.25	0.04	**5.87**

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNTS (Issue 16.1) Appendix B
FORECAST ACCOUNTS PROPOSED FOR CLEARING JANUARY 1, 2006

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	
			June 30, 2005 Actual balances		
Line No.	Account Description	Account Acronym	Principal (000's)	Interest (000's)	
1.	Lost Revenue Adjustment Mechanism	2002 LRAM	(224)	(22)	(a)
2.	Shared Savings Mechanism V/A	2002 SSMVA	139	9	(a)
3.	Sub-total F2002 deferral and variance accounts		(85)	(13)	
4.	Deferred Rebate Account	2005 DRA	(11,029)	(357)	
5.	Customer Communication Plan D/A	2005 CCPDA	-	-	
6.	Ontario Hearing Costs V/A	2005 OHCVA	3,909	85	(b)
7.	Gas Distribution Access Rule D/A	2005 GDARDA	42	1	
8.	Transactional Services D/A	2005 TSDA	(4,972)	(36)	
9.	Union Gas D/A	2005 UGDA	(223)	(3)	
10.	Unaccounted for Gas V/A	2005 UAFVA	927	13	
11.	Corporate Cost Allocation D/A	2005 CCAMDA	419	19	
12.	Gas Supply Risk Management Program D/A	2005 GSRMPDA	63	1	
13.	Storage Rights Compensation Costs D/A	2005 SRCCDA	365	2	
14.	Sub-total F2005 deferral and variance accounts		(10,499)	(275)	
15.	Total Deferral and Variance Accounts Requested for clearing		(10,584)	(288)	

Note (a): June actuals do not reflect the Audit subcommittee and DSM Consultative findings which will be incorporated in the September 2005 actual balances for clearance.

Note (b): OHCVA excludes any amounts relating to the Alliance/Vector remand hearing.

Note: These account balances will be replaced with actual September 30, 2005 balances when available.

2006 TEST YEAR
FINANCIAL IMPACT OF THE SETTLEMENT PROPOSAL

1. This exhibit has been filed in order to provide the Board with the financial impact of the Settlement Proposal (Exhibit N1, Tab 1, Schedule 1) against the Company's deficiency request filed at Exhibit E1, Tab 1, Schedule 1. Acceptance of the Settlement Proposal will increase the Company's gross revenue sufficiency in the 2006 Test Year by $15.5 million, from $114.0 million (Exhibit E1, Tab 1, Schedule 1), to $129.5 million as shown at Exhibit N1, Tab 2, Schedule 2. The financial impact of the Settlement Proposal is examined further in the numeric information presented within the balance of this exhibit, Schedules 2 through 6.

Rate Base (Exhibit N1, Tab 2, Schedule 3)

2. The Company's rate base forecast will increase by $0.3 million, from $3,596.2 million at Exhibit B1, Tab 1, Schedule 1 to $3,596.5 million (Exhibit N1, Tab 2, Schedule 3, p. 1, Line 13), as a result of the Settlement Proposal.

3. The working cash allowance component of rate base has been recalculated to reflect the impact of the Settlement Proposal with respect to the increased sendout volumes and the associated increase in gas costs included in the calculation (Exhibit N1, Tab 1, Schedule 1 – Issue 1.1), resulting in a $0.3 million increase. The working cash allowance calculation of $(4.6) million has been filed at Exhibit N1, Tab 2, Schedule 3, page 3, and compares to the level of $(4.9) million filed at Exhibit B1, Tab 4, Schedule 2.

Utility Income (Exhibit N1, Tab 2, Schedule 4)

4. Acceptance of the Settlement Proposal will result in a decrease to the Company's

forecast of net income in the amount of $(1.4)million, from $373.7 million at Exhibit F1.T2.S1 to $372.3 million (Exhibit N1, Tab 2, Schedule 4, p. 1, Line 20). The individual revenue and expense items which have been adjusted as a result of the Settlement Proposal can be examined at Exhibit N1, Tab 2, Schedule 4, on pages 1 through 3, and are discussed in the following paragraphs.

5. The adjustments to and resulting Settlement Proposal agreed to revenue from gas sales (Exhibit N1, Tab 2, Schedule 4, p. 1, Line 1), transportation of gas (Exhibit N1, Tab 2, Schedule 4, p. 1, Line 2) and gas costs (Exhibit N1, Tab 2, Schedule 4, p. 1, Line 8) reflect the impact of the Settlement Proposal with regard to increased volumes (Exhibit N1, Tab 1, Schedule 1 – Issue 1.1).

6. Other operating revenue will increase by $1.4 million, from $17.9 million (Exhibit C1, Tab 1, Schedule 1, Line 4) to $19.3 million (Exhibit N1, Tab 2, Schedule 4, p. 1, Line 4), as a result of the Settlement Proposal for the following:
   - revenue from other service charges (Exhibit N1, Tab 1, Schedule 1 – Issue 2.1); and
   - imputed revenue for the NGV program (Exhibit N1, Tab 1, Schedule 1 - Issue 10.1).

7. As a result of the Settlement Proposal, the Notional Utility Account amount of $12.3 million to be recovered in 2006 will be treated as a cost of service item and recovered within rates (Exhibit N1, Tab 2, Schedule 4, p.1, Line 12) instead of being recovered through a deferral account (Exhibit N1, Tab 1, Schedule 1 – Issue 16.3).

8. Municipal and other taxes will decrease by $(1.6) million, from $53.6 million (Exhibit D1, Tab 1, Schedule 1, p. 3, Line 10) to $52.0 million (Exhibit N1, Tab 2,

Schedule 4, p. 1, Line 13) as a result of a reduction in municipal taxes within the Settlement Proposal (Exhibit N1, Tab 1, Schedule 1 – Issue 14.1).

9. As a result of the Settlement Proposal, Utility income before income taxes will decrease by $(0.6) million, which will result in a decrease in income taxes excluding the tax shield provided by interest expense in the amount of $(0.2) million. The tax shield provided by interest expense will decrease by $(1.0) million as a result of the decline in the capital structure return component of long and short-term debt from 4.65% as filed at (Exhibit E1, Tab 1, Schedule 1, p. 1, Line 3, Col. 4) to 4.57% found at (Exhibit N1, Tab 2, Schedule 5, p. 1, Line 3, Col. 4) as a result of the Settlement Proposal (Issue – 7.1). Total income taxes will increase by $0.8 million, from $123.4 million filed at Exhibit D1, Tab 1, Schedule 1, Line 9 to $124.2 million (Exhibit N1, Tab 2, Schedule 4, p. 1, Line 19).

10. As a result of the Settlement Proposal, Utility net income will decrease by $(1.4) million, from $373.7 million (Exhibit F1, Tab 2, Schedule 1) to $372.3 million (Exhibit N1, Tab 2, Schedule 4, p. 1, Line 20).

<u>Capital Structure (Exhibit N1, Tab 2, Schedule 5)</u>

11. The proposed method and costs of financing capital requirements including the cost rates for the planned medium and long-term debt issues and for short-term debt (Exhibit N1, Tab 1, Schedule 1 – Issue 7.1) are incorporated into the capital structure found at (Exhibit N1, Tab 2, Schedule 5, p. 1). The overall rate of return on rate base of 8.01% includes a 9.42% interim rate of return on common equity as determined by the current Board approved formula which will be updated using October 2005 Long Canada Consensus Forecast for determining the Fiscal 2006 final revenue requirement (Exhibit N1, Tab 1, Schedule 1 - Issue 7.2).

12. Utility income in the amount of $372.3 million represents an indicated return of 10.35% on a rate base of $3,596.5 million, indicating a sufficiency in return in the amount of 2.34% in comparison to the requested overall rate of return in the amount of 8.01%. This results in a net sufficiency of $84.2 million and a gross revenue sufficiency of $129.5 million, as shown at Exhibit N1, Tab 2, Schedule 5.

13. Acceptance of the Settlement Proposal will result in a gross revenue sufficiency of $129.5 million, which is an increase of $15.5 million, as shown at Exhibit N1, Tab 2, Schedule 6, in comparison to the Company's sufficiency request filed at Exhibit E1, Tab 1, Schedule 1 in the amount of $114.0 million.

14. Within the originally filed overall sufficiency of $114.0 million filed at Exhibit E1, Tab 1, Schedule 1, page 1, the distribution related revenue requirement deficiency (excluding the impact of forecast commodity price changes) was $94.9 million as indicated in response to Board Staff interrogatory #1 (Exhibit I, Tab 1, Schedule 1). As a result of the Settlement Proposal the distribution deficiency inherent within the overall revenue sufficiency would decrease by $(15.5) million to $79.4 million.

Utility Impact Summary
2006 Test Year

Line No.		Col. 1 Reference	Col. 2 ($Millions)
1.	Utility rate base	N1.T2.S3.P1*	3,596.5
2.	Utility income	N1.T2.S4.P1	372.3
3.	Indicated rate of return	N1.T2.S5.P1	10.35%
4.	Requested rate of return	N1.T2.S5.P1	8.01%
5.	Sufficiency in rate of return	N1.T2.S5.P1	2.34 %
6.	Net sufficiency	N1.T2.S5.P1	84.2
7.	Gross sufficiency	N1.T2.S5.P1	129.5
8.	Revenue at existing rates	N1.T2.S6.P1	3,093.2
9.	Revenue requirement	N1.T2.S6.P1	2,963.7
10.	Gross revenue sufficiency	N1.T2.S6.P1	129.5

*N1.T2.S3.P1 refers to Exhibit N1, Tab 2, Schedule 3, page 1.

Utility Rate Base
2006 Test Year

Line No.		Col. 1 Original EB-2005-0001 Rate Base (Note 1) ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 ADR Utility Rate Base ($Millions)
	Property, plant, and equipment			
1.	Cost or redetermined value	4,695.8		4,695.8
2.	Accumulated depreciation	(1,666.3)		(1,666.3)
3.		3,029.5		3,029.5
	Allowance for working capital			
4.	Accounts receivable merchandise finance plan	0.1		0.1
5.	Accounts receivable rebillable projects	4.2		4.2
6.	Materials and supplies	26.2		26.2
7.	Mortgages receivable	0.9		0.9
8.	Customer security deposits	(36.6)		(36.6)
9.	Prepaid expenses	3.3		3.3
10.	Gas in storage	573.5		573.5
11.	Working cash allowance	(4.9)	0.3	(4.6)
12.	Total Working Capital	566.7	0.3	567.0
13.	**Utility rate base**	3,596.2	0.3	3,596.5

Note 1: Information from Col. 3 of Exhibit F1, Tab 3, Schedule 1, page 1.

Explanation of Adjustments to Utility Rate Base
2006 Test Year

Line No. Adj'd	Adjustment ($Millions)	Explanation
11.	0.3	**Working cash allowance**
		To reflect the impact on the Company's working cash allowance as a result of the changes within gas costs associated with volume adjustments as per the Settlement Proposal. This calculation can be found on Exhibit N1, Tab 2, Schedule 3, on page 3.

Working Capital Components - Working Cash Allowance
2006 Test Year

Line No.		Col. 1 Reference	Col. 2 Disburs-ements ($Millions)	Col. 3 Net Lag-Days (Days)	Col. 4 Allowance ($Millions)
1.	Gas purchase and storage and transportation charges		1,888.2	4.2	21.7
2.	Items not subject to working cash allowance (Note 1)		105.7		
3.	Gas costs charged to operations	N1.T2.S4.P1	1,993.9		
4.	Operation and Maintenance	N1.T2.S4.P1	348.0		
5.	Less: Storage costs		(6.4)		
6.	Operation and maintenance costs subject to working cash		341.6		
7.	Ancillary customer services		0.8		
8.			342.4	(31.5)	(29.5)
9.	Sub-total				(7.8)
10.	Storage costs		6.4	55.2	1.0
11.	Storage municipal and capital taxes		1.7	36.4	0.2
12.	Sub-total				1.2
13.	Goods and services tax				2.0
14.	Total working cash allowance				(4.6)

Note 1: Represents non-cash items such as amortization of deferred charges, accounting adjustments and the T-service capacity credit.

Utility Income
2006 Test Year

Line No.		Col. 1 Original EB-2005-0001 Utility Income (Note 1) ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 ADR Utility Income ($Millions)
	Revenue			
1.	Gas sales	2,288.4	27.2	2,315.6
2.	Transportation of gas	767.5	8.2	775.7
3.	Transmission and compression & storage	1.9		1.9
4.	Other operating revenue	17.9	1.4	19.3
5.	Interest and property rental	-		-
6.	Other income	0.3		0.3
7.	**Total revenue**	3,076.0	36.8	3,112.8
	Costs and expenses			
8.	Gas costs	1,967.2	26.7	1,993.9
9.	Operation and maintenance	348.0		348.0
10.	Depreciation and amortization	208.7		208.7
11.	Fixed financing costs	1.4		1.4
12.	Notional utility account recovery	-	12.3	12.3
13.	Municipal and other taxes	53.6	(1.6)	52.0
14.	Interest and financing amortization expense	-		-
15.	**Total costs and expenses**	2,578.9	37.4	2,616.3
16.	Utility income before income taxes	497.1	(0.6)	496.5
	Income taxes			
17.	Excluding interest shield	181.9	(0.2)	181.7
18.	Tax shield on interest expense	(58.5)	1.0	(57.5)
19.	Total income taxes	123.4	0.8	124.2
20.	**Utility net income**	373.7	(1.4)	372.3

Note 1: Information from Col. 1 of Exhibit F1, Tab 2, Schedule 1, page 1.

Explanation of Adjustments to Utility Income
2006 Test Year

Line No. Adj'd	Adjustment ($Millions)	Explanation
1.	27.2	**Gas sales**
		To reflect the impact on gas sales revenue of the updates to degree days and volumes as per the Settlement Proposal.
2.	8.2	**Transportation of gas**
		To reflect the impact on transportation revenue of the updates to degree days and volumes as per the Settlement Proposal.
4.	1.4	**Other operating revenue**
		To reflect the impact of an increase to other service revenue $0.8 million and to impute revenue to the NGV program $0.6 million as per the Settlement Proposal.
8.	26.7	**Gas costs**
		To reflect the impact on gas costs of the updates to degree days and volumes as per the Settlement Proposal.
12.	12.3	**Notional utility account recovery**
		To reflect the recovery of the Notional Utility Account in rates as per the Settlement Proposal.
13.	(1.6)	**Municipal and other taxes**
		To reflect the impact of a reduction to municipal taxes as per the Settlement Proposal.
17.	(0.2)	**Income taxes - excluding interest shield**
		To reflect adjustments to utility income taxes as a result of the above noted changes contributing to lower taxable income and income tax excluding the interest tax shield. The Utility's income tax calculations are found at Exhibit N1, Tab 2, Schedule 4, page 3.
18.	1.0	**Income taxes - tax shield on interest expense**
		To reflect a decrease in the tax shield provided by interest expense as a result of a decrease in the Company's return component of debt as per the Settlement Proposal.

Utility Taxable Income and Income Tax Expense
2006 Test Year

Line No.		Col. 1 Original EB-2005-0001 Utility Tax (Note 1) ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 ADR Utility Tax ($Millions)
1.	Utility income before income taxes (N1.T2.S4.P1)	497.1	(0.6)	496.5
	Add Backs			
2.	Depreciation and amortization	208.7		208.7
3.	Large corporation tax	4.9		4.9
4.	Other non-deductible items	1.2		1.2
5.	Total Add Back	214.8	-	214.8
6.	Sub total	711.9	(0.6)	711.3
	Deductions			
7.	Capital cost allowance - Federal	158.9		158.9
8.	Capital cost allowance - Provincial	158.8		158.8
9.	Items capitalized for regulatory purposes	29.7		29.7
10.	Deduction for "grossed up" Part VI.1 tax	5.9		5.9
11.	Amortization of share/debenture issue expense	2.5		2.5
12.	Amortization of cumulative eligible capital	0.1		0.1
13.	Amortization of C.D.E. and C.O.G.P.E	0.3		0.3
14.	Total Deduction - Federal	197.4	-	197.4
15.	Total Deduction - Provincial	197.3	-	197.3
16.	Taxable income - Federal	514.5	(0.6)	513.9
17.	Taxable income - Provincial	514.6	(0.6)	514.0
18.	Income tax provision - Federal	108.0	(0.1)	107.9
19.	Income tax provision - Provincial	72.0	-	72.0
20.	Income tax provision - combined	180.0	(0.1)	179.9
21.	Part V1.1 tax			2.0
22.	Investment tax credit			(0.1)
23.	Total taxes excluding tax shield on interest expense			181.8
	Tax shield on interest expense			
24.	Rate base (N1.T2.S3.P1)			3,596.5
25.	Return component of debt (N1.T2.S5.P1)			4.57%
26.	Interest expense			164.4
27.	Combined tax rate			35.00%
28.	Income tax credit			(57.5)
29.	Total income taxes			124.3

Note 1: Information from Col. 1 and Col. 2 of Exhibit D1, Tab 1, Schedule 1, page 2.

Utility Capital Structure
2006 Test Year

Line No.		Col. 1 Principal	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long term debt	2,180.5	60.63	7.44	4.51
2.	Short term debt	57.4	1.60	3.46	0.06
3.		2,237.9	62.23		4.57
4.	Preference shares	99.8	2.77	5.00	0.14
5.	Common equity	1,258.8	35.00	9.42	3.30
6.		3,596.5	100.00		8.01
7.	Utility income	($Millions)			372.3
8.	Utility Rate base	($Millions)			3,596.5
9.	Indicated rate of return				10.35%
10.	Sufficiency in rate of return				2.34 %
11.	Net sufficiency	($Millions)			84.2
12.	Gross sufficiency	($Millions)			129.5
13.	Revenue at existing rates	($Millions)			3,093.2
14.	Revenue requirement	($Millions)			2,963.7
15.	Gross revenue sufficiency	($Millions)			129.5

Change in Revenue Requirement
2006 Test Year

Line No.		Col. 1 ADR Settlement Proposal	Col.2 Original exhibits A, B, C, D E and F (Note 1)	Col.3 Change (Col.1-Col.2)
		($Millions)	($Millions)	($Millions)
	Cost of capital			
1.	Rate base	3,596.5	3,596.2	
2.	Required rate of return	8.01%	8.33	
3.		288.1	299.6	(11.5)
	Cost of service			
4.	Gas costs	1,993.9	1,967.2	
5.	Operation and maintenance	348.0	348.0	
6.	Depreciation and amortization	208.7	208.7	
7.	Fixed financing costs	1.4	1.4	
8.	Notional utility account recovery	12.3	-	
9.	Municipal and other taxes	52.0	53.6	
10.		2,616.3	2,578.9	37.4
	Miscellaneous operating and non-operating revenue			
11.	Other operating revenue	(19.3)	(17.9)	
12.	Interest and property rental	-	-	
13.	Other income	(0.3)	(0.3)	
14.		(19.6)	(18.2)	(1.4)
	Income taxes on earnings			
15.	Excluding tax shield	181.7	181.9	
16.	Tax shield provided by interest expense	(57.5)	(58.5)	
17.		124.2	123.4	0.8
	Taxes on sufficiency / (deficiency)			
18.	Gross sufficiency / (deficiency)	129.5	114.0	
19.	Net sufficiency / (deficiency)	84.2	74.1	
20.		(45.3)	(39.9)	(5.4)
21.	**Revenue requirement**	2,963.7	2,943.8	19.9
	Revenue at existing Rates			
22.	Gas sales	2,315.6	2,288.4	
23.	Transportation service	775.7	767.5	
24.	Transmission, compression and storage	1.9	1.9	
25.	Sub-total	3,093.2	3,057.8	35.4
26.	Rounding adjustment	-	-	-
27.	Revenue at existing rates	3,093.2	3,057.8	35.4
28.	**Gross revenue sufficiency / (deficiency)**	129.5	114.0	15.5

Note 1: From information contained in Exhibits A, B, C, D, E and F.

APPENDIX 3

ENBRIDGE GAS DISTRIBUTION INC.

2006 TEST YEAR

DECISION WITH REASONS

BOARD FILE NO. EB-2005-0001/EB-2005-0437

PARTIAL DECISION
(DATED DECEMBER 22, 2005)

FEBRUARY 9, 2006

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2005-0001
EB-2005-0437

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2006.

BEFORE: Pamela Nowina
Presiding Member and Vice Chair

Paul Sommerville
Member

Cynthia Chaplin
Member

PARTIAL DECISION WITH REASONS

December 22, 2005

TABLE OF CONTENTS

1 INTRODUCTION 1

1.1 THE APPLICATION 1

1.2 PARTIAL DECISION 1

2 PROPOSAL FOR A THREE YEAR DSM PLAN (2006-2008), INCLUDING O&M BUDGETS AND VOLUME ESTIMATES 2

2.1 BACKGROUND 2

2.2 BOARD FINDINGS 3

3 ATTRIBUTION OF BENEFITS IN JOINTLY DELIVERED PROGRAMS 6

3.1 BACKGROUND 6

3.2 BOARD FINDINGS 7

4 SHARED SAVINGS MECHANISM (SSM) INCENTIVE 9

4.1 BACKGROUND 9

4.2 BOARD FINDINGS 10

5 MARKET TRANSFORMATION PROGRAMS AND INCENTIVES 12

5.1 BACKGROUND 12

5.2 BOARD FINDINGS 13

6 DEMAND SIDE MANAGEMENT VARIANCE ACCOUNT (DSMVA) MECHANISM 16

6.1 BACKGROUND 16

6.2 BOARD FINDINGS 17

7 RECOVERY OF DSMVA FOR 2002 AND 2003 18

7.1 BACKGROUND 18

7.2 BOARD FINDINGS 18

8 EARNINGS SHARING FOR THE DELIVERY OF ELECTRICTY PROGRAMS 19

8.1 BACKGROUND 19

8.2 BOARD FINDINGS 19

1 INTRODUCTION

1.1 THE APPLICATION

Enbridge Gas Distribution Inc. ("EGDI", Enbridge", the "Company" or the "Applicant") filed an application dated March 18, 2005 with the Ontario Energy Board under section 36 of the *Ontario Energy Board Act, 1998*, for an order or orders approving or fixing just and reasonable rates for the sale, distribution, transmission and storage of gas for EDGI's 2006 fiscal year commencing January 1, 2006. The Board assigned file number EB-2005-0001 / EB-2005-0437 to the application.

On August 10, 2005 a Settlement Proposal was filed with the Board. The Board heard submissions from the parties and accepted the Settlement Proposal on August 15, 2005. The Board held an oral hearing commencing August 16, 2005 on the unsettled issues. The oral phase of the hearing was completed on October 27, 2005. EGDI Argument-in-Chief, Intervenor Argument and EGDI Reply Argument were filed with the Board on November 4, 2005, November 21, 2005 and December 5, 2005 respectively.

1.2 PARTIAL DECISION

This Partial Decision with Reasons addresses the following issues:

- Proposal for a three year DSM plan (2006-2008), including O&M budgets and volume estimates
- Attribution of savings in jointly delivered programs
- Shared savings mechanism (SSM) incentive
- Market transformation programs and incentives
- Demand side management variance account (DSMVA) mechanism
- Disposition of the DSMVA for 2002 and 2003
- Revenue sharing for the Applicant's delivery of electricity programs

Copies of evidence, exhibits, arguments, and transcripts of the proceeding are available for review at the Board's offices.

The Board has considered all of the evidence, submissions and arguments in the proceeding and has summarized the evidence and the positions of the parties to the extent necessary to provide context for its findings.

2 PROPOSAL FOR A THREE YEAR DSM PLAN (2006-2008), INCLUDING O&M BUDGETS AND VOLUME ESTIMATES

2.1 BACKGROUND

In this case the Company is seeking approval for a three year DSM plan to cover 2006, 2007 and 2008. This multi-year aspect of the Company's DSM proposal finds its origin in the Settlement Agreement in last year's rate proceeding, RP-2003-0203. In that Agreement, which was approved by the Board, the parties accepted the Company's DSM plan for 2005, subject to its commitment to file a multi-year plan at its next rate proceeding. The Company has met that commitment.

The Company's proposal includes specific annual budget amounts and what it terms "estimated volumetric savings" for each year of the proposed three year term:

Year	Budget ($ millions)	Estimated Volume Savings (million m^3)
2006	$18.9	84.4
2007	$20.3	86.3
2008	$21.5	90.4

Originally, fuel switching was part of the DSM Plan. However, the Company agreed to move the funds for fuel switching from the DSM budget to the Opportunity Development O&M budget.

Associated with the Company's proposal for a three year term is its request for guidance from the Board with respect to gross spending levels. Some intervenors have urged the Company to increase its planned spending to a stipulated higher percentage of utility revenue. The Company stated that it has been attempting to address this issue for a number of years, and that additional guidance from the Board would make the regulatory process more efficient. Specifically, the Company is seeking an endorsement from the Board that DSM spending in the range of 1 to 2 percent of utility revenue is appropriate. The Company proposes to increase DSM spending over 3 years up to a budget of approximately 1 percent of annual revenue. The Company also requested that the Board provide an opinion on simplifying the budget setting process by setting annual budgets as a percent of revenue.

The Company's proposed three year plan retains all of the elements of its existing program, but makes significant changes to the design and operation of these elements within the multi-year plan. These aspects of the Company's proposal will be considered elsewhere in this Partial Decision, but it is important to note that in addition to proposing a 3 year term for its plan, the Company seeks to make material changes in how the plan will operate and how it will account for and share plan outcomes with ratepayers.

The Company did not propose any change to the LRAM mechanism, which fixes all the assumptions for the calculations of lost revenues at the start of the year, with no change being made as a result of new information during the year.

2.2 BOARD FINDINGS

The concept of a multi-year plan has been generally well-received by all interested parties. The Settlement Agreement governing the 2005 DSM plan is evidence that there is at least a recognition that a multi-year format may lead to efficiencies and a better planning environment for DSM activities. Indeed the primary rationalization offered by the Company for its multi-year proposal is simply that an annual examination of the targets, budgets and programs is inefficient, and that engaging in the process less often, say every three years, is more efficient, and does not necessarily compromise ratepayer oversight or confidence in any aspect of the plan.

While there may be some agreement on the potential benefits of a change in the term of the plan, there is clearly no consensus on the Company's proposed changes to the specific elements of the plan.

In addition to their opposition to the changes to plan elements, a number of intervenors argued that the adoption of a new extended term for the Company's DSM plan should only occur after a review of the broader DSM environment. In their view, entrenchment of a three year plan at this time is inappropriate given material developments in the area. These developments include an enhanced engagement of electricity distributors in conservation and demand management (CDM) activities and a growing presence of the Federal government in pursuit of climate change initiatives.

Also important is the fact that the other major gas utility, Union Gas Limited ("Union"), has itself filed an application for a three year term for its DSM plan. Some intervenors, most notably the Consumers Council of Canada (the "Council") and the Industrial Gas Users Association ("IGUA") , argued that it would be more efficient to address and assess the differences between the DSM approaches of EGDI and Union prior to the adoption of a multi-year program for either. The elements of the respective programs have evolved separately for each utility. While the plans share a number of elements, important differences have developed in the respective plans over the years.

The Board finds that it is not appropriate to approve a three year term for the Company's DSM plan at this time. The Board considers that the sharply enhanced importance of conservation activities in the broad energy market today makes a review of the design of the DSM plans of both major gas utilities advisable. It is important to assess the extent to which the existing gas distribution DSM programs meet the needs of the distributors, the ratepayers and the broad public interest. The fact that the two utilities have developed markedly different approaches raises the possibility that efficiencies are being missed in the process, and that a convergence of the two plans may be appropriate. It is also important to consider and, where appropriate, accommodate the role of other energy market participants and government in the delivery and encouragement of DSM activities.

The Board will approve a one year DSM plan for EGDI, and will convene a generic proceeding to deal with a series of questions related to the DSM activities of EDGI and Union. It is intended that this generic proceeding will occur in the first half of 2006. We expect the output of the generic proceeding to be clear, detailed, binding direction to the natural gas utilities.

Among the areas that will be investigated in the generic hearing are several which directly address issues of this case. These are:

- Timing of the schedule for submitting and reviewing DSM plans. This would include a consideration of amending the plans in mid-course to incorporate intervenor suggestions, new information, and budget changes, and the appropriateness of linking the plan to the schedule for establishing distribution rates;
- Determination and use of planning assumptions for generic energy efficiency measures and custom projects;
- Budget as a percentage of utility annual revenue
- Structure and screening of programs including differentiating between market transformation, lost opportunity and enabling activities;
- Structure and use of LRAM, SSM and DSMVA;
- Process and content of program evaluations including the requirement for a third party audit process;
- Length of plan, as well as updating the plan and reporting requirements;
- A consideration of rules respecting free riders and attribution of energy savings;
- and,
- The appropriateness of directing specific DSM measures to low-income consumers.

The Board approves the Company’s proposed budget for 2006, which is $18.9 million. This figure represents an increase over the 2005 budget amount, but an increase which is consistent with the experience of recent years. The Company’s testimony that the budget was developed in the normal course using a “bottom-up” methodology was not seriously challenged by any intervenor. The Board will consider the other specific changes that the Company proposes to its plan elsewhere in this Partial Decision, but the findings will be limited to 2006. Where possible the Board will defer decisions on the issues listed above to the generic proceeding.

The Board will adopt the “volume savings estimate” for 2006 as the volumetric savings target for 2006, subject to adjustments consequential to other findings in this Partial Decision. The Board notes that the Company accepted a number of the Green Energy Coalition’s (“GEC”) assumption changes outlined in Undertaking J36.1. The Company will ensure that these adjustments are incorporated into the DSM plan for 2006 and will provide the results of all adjustments to the Board and all parties to the proceeding.

3. ATTRIBUTION OF SAVINGS IN JOINTLY DELIVERED PROGRAMS

3.1 BACKGROUND

This issue addresses the extent to which the Company is entitled to claim energy savings associated with jointly delivered DSM programs. The Company asserted that it is not proposing any change to the attribution rules it applies to such programs. It identified the following principles as governing the attribution of energy savings for DSM programs which are delivered under partnerships or other joint projects:

- The energy savings allocation is to be determined at the time the DSM plan is implemented, not later, such as during the audit.
- Savings allocation for any new programs introduced during the period of the plan will be dealt with in the same manner as other program assumptions.
- The Company may claim 100 percent of the DSM savings where the Company’s role was central to the program.
- For each program that represents over 5 percent of the TRC benefits in the DSM plan, the Company will provide supporting information regarding its role in the program.

Of these principles, the one attracting most interest from intervenors is that which purports to authorize the Company to take full credit for the energy savings experienced through a program in which the Company has played a “central role”. In the Company’s view it should be considered to have played a central role in a program if it initiated the partnership, initiated the program, funded the program, or implements the program.

One program put forward by the Company is the EnerGuide for Houses program. This is an NRCan program that the Company is supporting in its delivery area. The Company is claiming 100 percent of the attributable benefits for this program.

Some intervenors argued that the Company has not shown any significant impact on this program as a result of its participation. They suggested the attribution rate should be adjusted by increasing the presumed free rider rate from 8 percent to 90 percent. This would reduce the benefits for the Company from 92 percent of the total participation to 10 percent.

A number of intervenors submitted that for joint programs and programs funded by entities other than electric local distribution companies (“LDCs”), the utility should be able to claim the proportion of the benefits only where those benefits would not have occurred without the utility’s efforts.

Some intervenors stated that they support the concept of the Company working with partners because such joint efforts are likely to result in a more cost effective approach to the delivery of DSM programs. They proposed that each program be considered on a case by case basis, and that attribution of energy savings should depend on the actual level of participation by the Company, and the extent to which it has made a financial contribution to the program or program participants.

3.2 BOARD FINDINGS

As indicated above, the generic proceeding will address rules for attribution of energy savings. The Board must develop a balanced and efficient approach to the issue, which does not involve lengthy regulatory proceedings, and which is fair and easily implemented.

It is clear from a cursory review of the criteria the Company uses to support its current "central role" attribution that such a characterization is dependent on a number of assumptions that may be controversial in any given case. It is also clear that the criteria proposed by intervenors can be subject to the same uncertainties. The sharply enhanced interest in conservation of all forms of energy, and the apparent increasing role played by other market participants and government make it important to find a reasonable and fair attribution methodology, which has the confidence of all affected parties.

The Board is not in a position at this time to make any finding which would replace the Company's current practice. The Board finds that the Company may claim 100 percent of the benefits associated with DSM programs in which it plays a central role in the marketing and delivery of the program with a non-rate regulated third party.

However, the Board heard sufficient evidence in this case respecting the NRCan EnerGuide for Houses program to conclude that this program does not meet the Company's own criteria for establishing a central role. First, the Board notes that the financial contribution made by Enbridge to program participants is relatively modest compared to the total budget for the EnerGuide for Houses program. It is also apparent that this national program has not found extraordinary participation rates within the Company's franchise area, leading to the conclusion that its contribution is not exemplary, when compared to the program's general impact across the country. In these circumstances it is inappropriate for the Company to claim 100 percent of the energy savings associated with it. The Board is not convinced that the Company continues to play a central role in the EnerGuide for Houses program nor that it has provided a significant impact on increased market penetration. The Board appreciates that Enbridge provides non-direct financial roles that are important to the EnerGuide for Houses program. These roles include promotion and support for the program. The Company has played a historical role in developing the program. Accordingly, the Board finds that the Company can claim 50 percent of the net benefits. The volumetric savings target for this program only will be adjusted to reflect this finding.

GEC and the Company had differing views on the concept of free riders. The Board believes that clarity on the issue of free riders should be established in the generic proceeding. For 2006, the free rider percentage for the EnerGuide for Houses program will remain at 8 percent.

The Board expects that the electric and natural gas industries will co-operate and partner in the creation of TRC benefits and the reduction of program costs. If the Company is entering into a partnership with an electric LDC, the Board's current guidelines for the attribution of benefits will apply, pending the outcome of the generic proceeding. These guidelines were established in the Total Resource Cost Guide issued on September 8, 2005.

4. SHARED SAVINGS MECHANISM (SSM) INCENTIVE

4.1 BACKGROUND

The Shared Savings mechanism is designed to provide an incentive to the utility to aggressively pursue DSM savings. The existing SSM mechanism for the Company was initiated in 1999. The theory behind the incentive was to reward achievement of the TRC goal. Revenue flowed to the shareholder as results surpassed the forecast incentive threshold or pivot point. No payout to the shareholder was made when results fell short of the TRC target.

In this proceeding the Company proposed a fundamental change to the operation of the SSM. It proposed to derive revenue for the shareholder beginning with the first dollar of TRC savings at the rate of 5 percent of TRC achieved. This proposal effectively eliminates any performance threshold, and bases shareholder reward on all TRC results.

The Company's rationale for this change is based on three concepts. First, it suggested that it is fundamentally unfair to deny the shareholder participation in the program where it misses the target by a small amount and through no fault in its diligence or application to the DSM program. Second, in the Company's view, society begins to receive the benefit of the DSM activity as soon as the first unit of TRC is generated and denying the

Company a revenue reward until a target is achieved is unjust. Third, the Company's proposal adopts the mechanism put in place by the Board to encourage the electricity distributors in the province to embark on CDM activities.

The Company also stated that the present SSM is administratively problematic because of its reliance upon pivot point targets that are difficult to negotiate and settle. Intervenors have proposed various TRC determined SSM models ranging from 1 percent to 6 percent of net benefits with TRC pivot points ranging from 75 percent to 100 percent of the TRC target. As well, some intervenors submitted the current SSM should remain in place.

Some intervenors are concerned with the Company being rewarded for poor performance and that the Board should set a floor below which no rewards are paid out.

4.2 BOARD FINDINGS

The Board is satisfied that the SSM should be continued for 2006, with the following attributes:

- 100 percent of the target will be set at $158.1 million less the consequential adjustments of this Partial Decision.
- The SSM will be available for all TRC savings in excess of 75 percent of the established TRC target.
- For TRC savings between 75 percent and 99.9 percent of the TRC target, an SSM amount of 18 percent of TRC savings in excess of 75 percent, plus,
- For TRC savings between 100 percent and 109.9 percent of the TRC target, an SSM amount of 15 percent of TRC savings in excess of 100 percent, plus,
- For TRC savings between 110 percent up to 120 percent of the TRC target, an SSM amount of 12 percent of TRC savings in excess of 110 percent, plus,
- For every subsequent increase of 10 percent over the TRC target, the marginal SSM rate shall decline by a further 3 percent until it equals 3 percent.

This structure has been elected because we believe that the format represents an appropriate balance between shareholder and ratepayer interests. The fact that it was developed earlier this year for Union (EB-2005-0211) is helpful to us. However, the principle of alignment of EGDI and Union mechanisms is an issue best left to the generic proceeding.

The elimination of a pivot point or target threshold is fundamentally inconsistent with the purpose of the mechanism. The core purpose of the mechanism is to incentivize the Company to achieve and surpass the established TRC target. It is a reward for exemplary performance, not a payout for any performance, no matter how meager. This observation was made by virtually every intervenor that commented on it, and is compelling. In our view, this disposes of the first two grounds advanced by the Company in support of this change in the SSM.

Structuring an SSM with a pivot point at less than 100 percent recognizes that material benefits are generated for ratepayers at lower levels of achieved savings. For example, the Company achieved significant TRC benefits in 2004 at a performance level less than 100 percent yet will likely receive no incentive payment. The Board considers the mechanism approved herein to strike an appropriate balance between fairness to the Company in recognizing benefits achieved, while retaining an appropriate incentive for exceptional performance.

The Company's argument that its proposed change in the SSM should be approved because it incorporates the same approach as that adopted for the electricity distributors is also flawed. This rationale ignores the fact that the gas utilities and the electricity utilities are at different ends of the DSM experience scale. The gas utilities have been engaged in DSM activities for a substantial period, and have developed a high degree of expertise in developing, assessing and implementing programs in a regulated environment. Most electricity distributors, in contrast, have much less experience in such programs. The establishment of the 5 percent of all TRC SSM for electricity distributors was intended to create a simple and easily implemented incentive plan in a transition period. Its simplicity was recognition of the distributors' relative lack of experience in DSM delivery. It as likely that the electricity SSM approach will evolve into something closer to the approach followed in gas, than the obverse.

5 MARKET TRANSFORMATION PROGRAMS AND INCENTIVES

5.1 BACKGROUND

Market transformation programs are arguably a special category of DSM activity which seeks to embed, often through the introduction of energy saving equipment, industrial plant and appliances, energy savings that are substantial and of long duration. In these characteristics such programs are different than many other DSM programs, which are often shorter term approaches, more modest in their single effect.

Market transformation programs can offer very substantial and sustainable savings, but they can be more expensive to deliver. Many observers regard market transformation programs as offering highly desirable results, which can only be achieved through more programmatic, resource intensive and rigorous efforts by DSM providers.

The Company proposed to spend approximately $3.4 million in market transformation programs over the three years of the Plan for the following programs:

- Contractor Performance Program;
- White Goods;
- EnerGuide for New Houses;
- EnergyStar Windows;
- EnerGuide Label for Natural Gas Fireplaces; and
- Low Income Programs.

The Company proposed a budget of just under $1 million during the plan for a high efficiency boiler market transformation initiative. The Company proposed to focus both on hydronic boilers in sizes of 300,000 BTU and greater and high efficiency boilers that meet minimum combustion efficiencies. Pollution Probe and GEC suggested an alternative design for this program that focuses on an incentive scheme.

Some intervenors strongly supported the further development of market transformation programs and suggested that it is critical that the Company commit itself definitively to the pursuit of such programs, which offer a new and largely undeveloped opportunity for conservation gains.

While acknowledging the potential for market transformation programs, the Company's proposed commitment to these activities is marginal in light of its overall DSM budget, and dependent on the existence of specific incentives directed to the shareholder.

For example, the Company seeks approval for its participation in the Energy Star windows program, but argued that a program-specific incentive, specifically $300,000, is appropriate to encourage the Company to undertake the initiative. Some intervenors rejected this approach, suggesting that any consideration of such an incentive should be part of the next rate case.

Still others took the position that the proposed annual payment of $300,000 per year over 3 years is excessive for moving the market share by an anticipated 5 percent per year. Some intervenors were uneasy about the establishment of a separate category of DSM programs, called "market transformation" which is subject to distinct and generous incentives. In their view, such programs should be considered within the rules and practices governing DSM activities as a whole.

The Company justified a separate treatment for market transformation programs on the grounds that such programs may have impacts on system expansion expectations. That is to say, that the Company has a concern that these programs may be so successful that the anticipated and orderly economic expansion of the gas distribution system will be curtailed.

5.2 BOARD FINDINGS

The disputes which characterize this aspect of the Company's DSM proposal are profound, and concern nothing less than the appropriate future direction of its DSM activities. It is quite likely that the conventional DSM activities of the Company have hit, or will hit a plateau where their effectiveness diminishes. This outcome is likely given the entry of new players in the DSM environment, most notably the electricity distributors and the government, and the fact that many DSM programs directed to "low hanging fruit" have already achieved most of what they can achieve. The next natural step in the evolution of this activity is likely to be development of market transformation programs. These programs have a different economic profile than most current DSM activities. Their effect is often expected to be long term, their implementation may also be long term, and their costs are often higher than conventional programs.

The nature of this development is treated most effectively in GEC's evidence, which suggested that the Company is at a "crossroads" with respect to its DSM portfolio.

For these reasons, the Board will examine market transformation programs, the budget process associated with them and the appropriateness of program specific incentives in the generic proceeding. In that proceeding, the Company should be prepared to document its concerns about the presumed limitations on system development and growth occasioned by market transformation programs, if it wishes to have its concerns on this aspect considered.

In the interim, pending the completion of the generic proceeding, the Board will approve the Company's market transformation budget of $987,000 for 2006. The Board expects that the market transformation programs that are part of the DSM plan will be included in any proposed DSM plans for 2007 and 2008.

The Board also approves the Company's proposal respecting the EnergyStar windows project, including its proposal for a potential $300,000 incentive for the shareholder provided the program meets its 5 percent market impact target. The Board has some concerns that the target may be overly cautious. Certainly Mr. Neme, in his evidence, suggested that a more ambitious target is warranted. The fact is that few in the Ontario environment have much directly relevant experience in such programs, and while the experience in other jurisdictions is and will be helpful as this aspect of DSM develops, the Board considers that the Company's proposal is not unreasonable. The Board will regard this program as in the nature of a pilot program, learnings from which will inform future practice.

GEC and Pollution Probe recommended that the Board mandate a condensing boiler market transformation project, which would have the Company support purchases of such boilers by industrial customers through direct purchase subsidy equivalent to 50 percent of the incremental costs associated with the purchase.

It would appear that this kind of program is very like the kind of market transformation effort that may be needed to achieve conservation targets in the future. The Board is reluctant however to mandate the program, without a more thorough evidentiary foundation. Accordingly, we will require the Company to work with intervenors to develop such a program for its next rate case. The Company's resulting proposal should attempt to expose all elements of the program, and the remaining points in dispute between itself and the intervenors. The Board recognizes that there may be consequential changes to this approach arising from the generic proceeding.

The Board has the same view with respect to the market transformation program directed to low income consumers and directs the Company to engage in the same process as outlined above to develop an approach to this aspect of market transformation.

The Board is concerned that the Company has not focused sufficient attention on the circumstances effecting the participation of low income consumers. The issue of programs for low income consumers will be addressed in the generic proceeding. However, to ensure attention to this issue in EGDI's 2007 case, the Board requests that the Company provide an exposition and explanation of its conservation planning for this category of customer at the time of its next rate proceeding.

6 DEMAND SIDE MANAGEMENT VARIANCE ACCOUNT (DSMVA) MECHANISM

6.1 BACKGROUND

The DSMVA is a variance account which is designed to enable the Company to track and recover amounts expended on DSM activities in excess of the Board-approved DSM budget. As currently defined, the recovery of such excess spending is limited to a ceiling of 20 percent over the Board approved budget. In addition, the Company may only recover the funds captured in the account if it has achieved 100 percent of its forecast energy savings, which is its volumetric savings target. The Company proposed to modify the existing mechanism of the DSMVA to permit recovery of excess spending after only 80 percent of the volumetric savings target having been achieved. The 20 percent excess spending ceiling would be retained. In fact, the Company has proposed that the volumetric savings "target" should be eliminated for the purposes of its plan, and replaced with a volumetric savings "estimate". This proposed innovation is designed to address what the Company feels is a flaw in the existing structure of the DSM. It contends that for shared saving incentive purposes, it should not have to attain a hard energy savings target, but rather should get credit, and revenue, for any and all savings attributed to its program. The savings target then becomes a savings estimate. This aspect of the Company's proposal is dealt with in Section 4 of this Partial Decision. For the purposes of the discussion in this section of the Partial Decision, the Board will use the prevailing terminology, which is "volumetric savings target".

The Company has outlined the following rationale for its request to reduce the threshold for access to the DSMVA to 80 percent:

- There is equal uncertainty in the forecasting of volumetric estimates as there is in forecasting DSM expenditures. In recognition of this, the Board should relax the 100 percent rule.
- There is a risk in accessing the DSMVA if the Company believed it had achieved the volumetric target, but learns through the audit process that the volumetric target had not been achieved and that the expenditures are therefore not recoverable.

- Under the current structure, if actual results for a given year are very close to the savings estimate near year-end, the Company does not have adequate time to take advantage of the DSMVA. The Company's proposal of reducing the threshold to 80 percent, would allow access to the DSMVA earlier to support its programs. The Company submitted that this is consistent with the conservation culture which the government of Ontario is promoting.
- The Company submitted that reducing the threshold to 80 percent is not equivalent to increasing the budget by 20 percent. The Company witness acknowledged that Board approval will be required to clear the DSMVA. Therefore, the onus remains on the Company to show that the use of funds is reasonable and used in a cost-effective manner.

Some intervenors argued that the Company's proposal to access the DSMVA after only 80 percent of the volumetric target is achieved is unnecessary. They asserted that the Company already has an incentive to achieve energy savings beyond its target through the SSM.

No intervenors supported the proposed change to the DSMVA.

6.2 BOARD FINDINGS

The School Energy Coalition ("SEC") submitted that the Board should allow the Company to access the DSMVA only for spending on TRC benefits in excess of 100 percent of the TRC target. In SEC's view, it is inappropriate to commit additional funds before the TRC target has been met. The TRC target is based on monetization of the volumetric energy savings achieved by the Company's plan. It is a widely accepted metric which takes into account a variety of factors which attempt to place a specific monetary value on energy use avoided by conservation.

In the Board's view, in considering the recovery of overspending a metric based on the money value of the savings is most appropriate.

In addition, the Board considers that, while all forecasting is subject to some degree of uncertainty, this area is no more prone to forecast error than any other aspect of Company operations. The Company's argument that this uncertainty should result in a relaxed approach to thresholds governing the variance account misses the central point. The Board approves a budget for the DSM plan and expects the Company to operate within its limitations. Excess spending in any amount is not a desired outcome. Where it occurs, it is reasonable to permit recovery of overages only when the core objectives of the plan have been realized, and only to a defined ceiling. For the purposes of the variance account going forward this means that excess spending less than 20 percent of the Board approved budget may be recovered, but only where the Company has achieved its TRC target. The Board recognizes that there may be circumstances where the Company may not be certain of recovery late in the year, because it is uncertain as to its achievement of its TRC target. The cure for this eventuality is not relaxed targets or softened thresholds. The appropriate response is enhanced program tracking and forecasts.

7 RECOVERY OF DSMVA FOR 2002 AND 2003

7.1 BACKGROUND

The Company is seeking approval for the clearance of $252,000 recorded in the 2002 DSMVA, and $1,008,000 in the 2003 DSMVA, plus interest.

The Company submitted that it has complied with the mechanics of the DSMVA and that it is appropriate for the 2002 and 2003 DSMVA to be approved for clearance on January 1, 2006.

7.2 BOARD FINDINGS

The Board did not hear any material arguments from intervenors opposing the clearance of the 2002 and 2003 DSMVA. The Company has stated that it has exceeded the threshold volume targets in those years and has complied with the requirements of the DSMVA.

SEC proposed that, in future, the Board should require the Company to submit evidence demonstrating that all of the conditions for clearance have been met. The Board considers that there is merit in the suggestion at least to the extent that we will include this issue as part of the filing requirement aspects to be considered in the generic proceeding.

The Board approves clearance of $252,000 recorded in the 2002 DSMVA and $1,008,000 in the 2003 DSMVA plus interest.

8 EARNINGS SHARING FOR THE DELIVERY OF ELECTRICITY PROGRAMS

8.1 BACKGROUND

The Company is seeking approval from the Board for its earnings sharing proposal in respect of earnings generated by DSM services provided under contract to electric LDCs. The Company proposed to retain one half of all net earnings generated through program development and delivery services provided to electric LDCs. The other half would be credited to ratepayers. The Company proposed to establish a deferral account to track and retain amounts generated by this activity, for disposal in its next rate case.

The Company submitted that its experience delivering certain DSM programs and contacts with key channel partners offer electricity LDCs an option of partnering with the Company to accelerate results and leverage the Company's existing processes and infrastructure to the benefit of the ratepayers of each utility.

Some intervenors submitted that a 50:50 earnings sharing proposal is far too generous to the utility shareholder, given that it appears that it is based on leveraging existing programs and may not involve a great deal of incremental work.

8.2 BOARD FINDINGS

As outlined in the previous section of this Partial Decision, the Company has developed considerable expertise in the management of the DSM portfolio. Sharing of this expertise supports the advancement of a conservation culture. A revenue incentive provides motivation to the Company to share its expertise.

The Board approves the Company's proposal in respect of earnings generated through its partnering with electric LDCs to develop and deliver cost-effective conservation and demand management programs. This approval is for the test year only. The Board considers that the issue of the terms of and the appropriateness of gas utility engagement as a service provider to electricity LDCs should be included in the range of questions referred to the generic proceeding.

The Board approves the Company's request to establish a deferral account to track and account for revenues generated by this activity during the test year.

The matter of intervenor and Board costs will be addressed in the final decision.

Dated at Toronto, December 22, 2005

Signed on behalf of the Panel

Original signed by

Pamela Nowina
Presiding Member and Vice Chair