Ontario Energy Board
Commission de l'Énergie de l'Ontario

Ontario

RP-2002-0147 1

EB-2002-0446

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, S.O. 1998, c.15, Sched. B; 2

AND IN THE MATTER OF an Application by Natural Resource Gas Limited for an order or orders approving or fixing just and reasonable rates and other charges for the sale and distribution of gas for the period commencing October 1, 2002 and commencing October 1, 2003. 3

4

BEFORE: 5

Paul Vlahos 6
Presiding Member

Sally Zerker 7
Member

Art Birchenough 8
Member

DECISION WITH REASONS 9

June 27, 2003 10

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1. THE APPLICATION AND THE PROCEEDING 13

Natural Resource Gas Limited ("NRG", the "Applicant", or the "Company") filed an Application with the Ontario Energy Board ("OEB"or the "Board") dated December 19, 2002 (the "Application") pursuant to section 36 of the Ontario Energy Board Act, S.O. 1998, c. 15, Schedule B (the "Act"), requesting an order or orders approving or fixing just and reasonable rates and other charges for the sale and distribution of gas for the Company's 2003 fiscal year, commencing October 1, 2002 (the "2003 test year" or "2003 fiscal year"), and for its 2004 fiscal year commencing October 1, 2003 (the "2004 test year" or "2004 fiscal year"). 14

The Board issued an interim order (EB-2002-0447) on September 26, 2002 directing that the rates and other charges approved for the fiscal 2002 year be declared interim, effective October 1, 2002, for a period of no longer than one year, and subject to change retroactive to that date. 15

On February 24, 2003, the Board issued an order under docket number EB-2003-0007 approving an increase of $0.072654 per m^3 for increased commodity costs. 16

On April 24, 2003, the Board issued an order under docket number EB-2003-0061 approving an increase of $0.028826 per m^3 for increased commodity costs. 17

The Board issued a Notice of Application dated December 20, 2002, along with directions for service of the Notice. Enbridge Gas Distribution Inc. ("Enbridge") and Union Gas Limited ("Union") intervened. 18

On January 17, 2003, the Board issued Procedural Order No. 1, which specified dates for the discovery phase of the proceeding and for a settlement conference to take place on Tuesday, May 27, 2003. 19

A stakeholder conference was held at the Board's offices on February 13, 2003 to review NRG's prefiled evidence and to discuss the issues relevant to the hearing of the Application. 20

On April 22, 2003, the Board issued Procedural Order No. 2, cancelling the settlement conference, listing the Board-approved issues for the proceeding, and setting May 26, 2003 as the date for commencement of the oral hearing. 21

The hearing of the oral evidence began on Monday, May 26, 2003 and concluded on Wednesday, May 28, 2003 with the Company's reply submissions to Board Staff's summary. 22

The participants and their representatives were Mr. Richard King for the Applicant and Mr. Mike Lyle for Board Staff. Because of the absence of other intervenors, Board Staff took an active role in the proceedings. 23

Counsel to NRG called W. Blake, the Company's President and General Manager, S. McCallum, 24
the Company's Financial Manager, and R. Aiken, a Principal with Aiken and Associates, as witnesses to testify on behalf of the Company.

Based on the Applicant's updated evidence, the following is a summary of its proposals related to 25
the revenue requirements for fiscal 2003 and 2004.

26

	Fiscal 2003	Fiscal 2004
Rate Base ($)	9,521,226	9,834,952
Rate of Return on Rate Base(%)	9.89	10.50
Return on Common Equity(%)	9.69	10.02
Cost of Capital ($)	941,649	1,032,670
Cost of Service ($)	8,869,784	9,525,340
Gas Sales Revenue (at existing rates)($)	8,913,397	10,309,488
Other Operating Revenue (net)($)	624,758	634,300
Income Taxes ($)	40,163	52,185
Gas Supply Cost (Deficiency)/Sufficiency ($)	(555,800)	77,500
Distribution (Deficiency)/Sufficiency ($)	57,600	76,000
Gross Revenue (Deficiency)/Sufficiency ($)	(498,168)	153,485

Copies of all the evidence, exhibits and submissions in this proceeding, together with a verbatim 27
transcript of the hearing, are available for public review at the Board's offices. The Board has chosen to summarize the evidence only to the extent necessary to explain its findings.

The format of this decision generally follows the Board's traditional approach to determining cost 28
of service revenue requirement. Rate Base is dealt with in Chapter 2, Utility Income in Chapter 3, Capitalization and Cost of Capital in Chapter 4, Cost Allocation and Rate Design in Chapter 5, Deferral and Variance Accounts in Chapter 6, and Revenue Sufficiency/Deficiency and Rate Order in Chapter 7.

2. RATE BASE 29

NRG proposed a total rate base of $9,521,226 for the 2003 test year and $9,834,952 for the 2004 30
test year. These levels reflect proposed capital expenditures of $1,341,051 for 2003 and $920,848 for 2004.

The Board makes determinations on the following two items: a) the proposed Norfolk East project, 31
and b) capital gains from the sale of certain land and buildings.

Norfolk East Project 32

The Norfolk East project accounts for $411,384 of the proposed capital expenditures for 2004. Of 33
this amount, $376,912 is for the main project and $34,472 is for service line additions, meters and regulators required to serve new customers. The Company indicated that this project is primarily being undertaken to serve tobacco farms. The Company is expecting to complete this project before August 2004, in time for the 2004 tobacco curing season.

Board Staff noted that the Applicant had agreed that the Norfolk East project may be discretionary, 34
and that if the Board wished to defer a project then it would be appropriate to defer this project. Board Staff suggested that the Board may wish to consider deferring the inclusion of the cost of this project in rate base for the 2004 test year.

The Applicant noted that the project is economic, is driven by customer demand, has already been 35
postponed from fiscal 2003 to fiscal 2004, and is tied to another project which the Company had been planning for 2005 (the Norfolk South project). This latter project was expected to feed off the Norfolk East project. Postponement of the Norfolk East project would automatically mean postponement of the Norfolk South project.

Board Findings 36

The Board notes that the Norfolk East project is being undertaken primarily to serve tobacco 37
accounts. Given the Company's own evidence that this industry continues to be on the decline, the less than rigorous survey in forecasting customer attachments, the late timing of the project coming into rate base in the 2004 test year, and the Company's evidence that it could be postponed, the Board is not prepared to approve this expenditure for rate-making purposes at this time. If the Company continues to feel confident about the economic viability of this project, the Company may of course proceed with it in fiscal 2004. However, the Board expects a stronger justification of the economic feasibility of the project for inclusion in future rates.

Gain from the Disposal of Old Land and Buildings 38

NRG moved to new office space in June 2002, and proposed to bring the cost of the new facilities into fiscal 2003 rate base. The total cost of the new land and building, including interest on the deferred balance, is $754,031. 39

NRG sold its old facilities for $156,224. The net book value of the old facilities was $67,514. The resulting gain from the sale ($88,710) was recorded on the statement of earnings for 2002. 40

The Applicant noted in evidence that the treatment of the gain from the sale is consistent with generally accepted accounting principles. The Applicant did not consider whether it should share the gain with customers. 41

Board Staff suggested that the Board may wish to consider whether NRG should share the gain with its customers or even whether customers should receive the full gain. 42

The Company suggested that the Board be guided by how it has treated other gas utilities with respect to asset disposition. It cited two instances in which the Board had required a utility (Enbridge Gas Distribution Inc.) to share similar gains on a 50/50 basis. The Company submitted that the Board should not find that the customers receive more than half the capital gain. 43

Board Findings 44

The Board finds that it is reasonable in the circumstances that the capital gains be shared equally between the Company and its customers. In making this finding the Board has considered the non-recurring nature of this transaction. 45

3. UTILITY INCOME 46

Based on existing rates, the Applicant's evidence was that total revenue (including net income from ancillary programs) would be $9,538,155 and $10,943,788 for the 2003 and 2004 test years, respectively. Cost of service, other than return on rate base, net other operating revenue and income taxes for the respective years were proposed at $8,869,784 and $9,525,340. 47

In addition to the revenue and cost of service changes that flow from the Board's findings in this decision, the only item that requires specific Board findings is regulatory costs. The components of the proposed regulatory costs for the two years combined are shown in the table below. 48

49

Item	Amount ($)
Legal Fees	62,000
Intervenor	5,000
OEB Proceeding	15,000
Transcripts	7,500
Consulting	50,000
Printing	6,000
Mailing	2,000
Travel/Accommodation	4,000
Advertising	3,500
OEB Fixed	25,000
Total Regulatory Costs	180,000

The Company expected to incur regulatory costs of $180,000 for fiscal years 2003 and 2004 and planned to expense these equally between the two test years. Of these combined 2003 and 2004 regulatory costs, $155,000 is related to proceedings before the Board and $25,000 is the annual assessment by the Board. 50

The Company stated that it had forecast regulatory costs to be significantly higher than in the last proceeding as it had expected that this proceeding would result in an oral hearing rather than being resolved through a settlement agreement. However, the Applicant testified that the legal and consulting costs would be approximately $6,400 less if the hearing was shorter than the one week period that it had anticipated. The response to an undertaking indicated that transcript costs would be $5,975 rather than the anticipated $7,500. Regarding the $15,000 in OEB costs proposed for the two test years together, the Company stated that they had been billed $13,771 for the Board's costs in the RP-2000-0126 proceeding. About 98% of this amount was for fees paid to a consultant hired by Board Staff to help them prepare for the proceeding. The Company indicated that it did not have a figure for Board costs for the current proceeding and expected the Board to make appropriate adjustments. 51

On cross-examination, the Company noted that, in light of the significant regulatory costs for a utility of NRG's size, it would be willing to consider alternative methods of regulation. NRG stated that it was open to suggestions from the Board about changing the regulatory mechanism, including 52 moving to a three year test period, a one year test period with simplified filings, returning to a process which involves ADR, or moving to a PBR approach.

Board Findings 53

In light of the fact that no consulting fees were incurred by Board Staff, the Board expects that no costs will be billed to NRG for this proceeding. Given this, and the reduced legal fees, transcription and other costs due to the shorter than anticipated hearing, and cancellation of the settlement conference, the Board finds that it is appropriate to reduce the forecast $180,000 for regulatory costs by $27,500. 54

For rate-making purposes, the Board deems that 50% of the $152,500 approved regulatory costs, or $76,250, shall be expensed by the Company in each of the 2003 and 2004 test years. 55

The Board welcomes the Company's openness to new regulatory mechanisms which will reduce the burden of regulatory costs on NRG ratepayers. The Board believes that the move to a two year test period has proved to be a positive step. Therefore, the Board would welcome a filing for a three year test period in NRG's next rates filing. While the Board acknowledges the greater difficulty in forecasting three years out, the Board believes that this is outweighed by the benefits in reducing the regulatory burden for NRG, its ratepayers and the Board. The Board directs Board Staff to enter into discussions with the Company to address any implementation issues which arise from a move to a three year test period and to report back to the Board by the end of this calendar year. 56

4. CAPITALIZATION AND COST OF CAPITAL 57

NRG's proposed capitalization and cost of capital are shown in the table below. 58

59

Capital Component	2003 test year		2004 test year	
	Average Amount ($)	Rate (%)	Average Amount ($)	Rate (%)
Long-Term Debt	3,561,147	11.38	4,173,725	11.60
Short-Term Debt				
Operating Loan	118,000	6.17	118,000	7.52
Unfunded Debt	1,081,466	6.17	625,751	7.52
Common Equity	4,760,613	9.69	4,917,476	10.02
Total Capitalization	9,521,226	9.89	9,834,952	10.50

The Board deals with each capital cost component below. 60

Short-Term Debt 61

NRG's proposal shows short-term debt of $118,000 for each of the 2003 and 2004 test years, and unfunded debt of $1,081,466 and $625,751 for the 2003 and the 2004 test years, respectively. The Company continues to use an operating loan from an affiliated company to finance its short-term debt. The interest rate on this operating loan is at prime plus 150 basis points. The Company projected prime rates of 4.67% for the 2003 test year and 6.02% for the 2004 test year, resulting in cost rates of 6.17% and 7.52% for the respective years. NRG proposed that these rates also be used for the purpose of calculating costs on the unfunded debt. 62

Board Staff suggested that the Board may wish to consider whether the prime rate forecast for the 2004 test year is excessive in light of recent market developments, including the appreciation of the Canadian dollar and a decline in inflation. 63

NRG conceded that events which created greater uncertainty in forecasting interest rates had indeed occurred since it filed its updated projections of the prime rate in March 2003. NRG stated that it was prepared to accept that 5% be used as the projection of prime for the 2004 test year. 64

Board Findings 65

The Board agrees that 4.67% is a reasonable forecast for the prime rate to be used for the purpose of establishing cost rate on NRG's short-term debt for the 2003 test year. The Board therefore approves a short term debt rate of 6.17% for the 2003 test year. 66

The Board's findings on debt rates for the 2004 are discussed in the section on long-term debt. 67

Long -Term Debt 68

The table below shows the various components of NRG's long-term debt and the associated cost rates in NRG's proposal. 69

70

Debt Component		2003 test year		2004 test year
	Average Amount ($)	Interest Rate (%)	Average Amount ($)	Interest Rate (%)
Junsen Loan	951,000	9.69	951,000	10.02
Junsen Debenture	208,928	11.03	1,125,945	11.03
Imperial Tobacco	35,083	6.00	N/A	N/A
Imperial Life	2,366,136	11.80	2,096,780	11.80
Total Long-Term Debt	3,561,147	11.38	4,173,725	11.60

The Imperial Life loan was entered into in June1994 with an original amount of $3,750,000, an interest rate of 11.8% per annum, and a maturity date of July 31, 2009. The loan agreement provides for blended monthly payments of principal and interest of $44,525. 71

The Imperial Tobacco loan was due and paid in October 2002. The original amount of this loan was $671,000 and interest was charged at 6%. Principal payments of $125,000 each were made in October 2000 and October 2001. 72

All of NRG's remaining long-term debt is held by an affiliated company, Junsen Limited, now 27 Cardingan Inc., which is fully-owned by NRG's sole owner. The maximum amount which can be advanced on the Junsen loan is $1,066,000. However, the amount advanced on the loan is anticipated to remain constant at $951,000. The interest rate is set at the same level as NRG's return on common equity subject to a floor of 9.25%. No principal payments on this loan are due until after the Imperial Life loan has been paid. 73

The Junsen debenture matures in 2010. This debenture currently has a maximum draw of $1.3 million. The maximum draw has been raised from time to time. It is anticipated that this cap will be increase in the near future to provide room for additional borrowing from this source. The average amount borrowed on the Junsen debenture is forecast to increase in the 2004 test year, compared to the average amount borrowed from this source in 2003. The interest rate on this loan is 11.03%. In addition, there is a standby fee of 2% on the undrawn amount. For the purposes of rate-making, only a 0.75% standby fee on a maximum undrawn amount of $500,000 is factored into rates. The increase in the average amount drawn on the Junsen debenture will lead to higher carrying costs, particularly in light of the fact that a significant portion of this higher draw arises from the reduction in the unfunded debt amount on which interest is deemed to be paid at the short-term debt rate. 74

The Company asserted that it would not be able to borrow from outside sources at lower rates than the rates it is paying for the Junsen Loan and the Junsen Debenture. However, on cross-examination, the Company stated that it had entered into "very preliminary" discussions with two financial institutions. These financial institutions had indicated that they would be interested in reviewing a 75 proposal to finance the entire debt of the Company. The preliminary rates that had been discussed with these financial institutions was somewhat over 8%. Some calculations done recently by the Applicant showed that the Company would only save on carrying costs if it was able to re-finance its entire debt at a rate lower than 8.75%.

NRG testified that penalties of approximately $467,000 would be incurred to pay off the existing 76
loans. In addition, there would be transaction and other costs of $250,000. These would have to be added to NRG’s current debt, and would have to be considered when determining the new level of carrying costs.

NRG testified that the pre-payment penalty clause in the Junsen debenture agreement had only been 77
added in 1998 at the same time as the cap on the draw was raised from $1.0 million to $1.3 million. The testimony of NRG was that inserting the pre-payment penalty into the agreement was consideration for the increase in the cap that the Company needed at that time. However, this increased room in the cap has not been used to date.

Board Staff suggested that, in light of the evidence about the possibility of refinancing its long-term 78
debt, the Board may wish to consider deeming lower interest charges on long-term debt than currently exists in NRG’s debt instruments.

NRG argued against this approach. It argued that the Board should only take this approach if it was 79
of the view that the Company had been imprudent in not refinancing to date. NRG submitted that such a finding would not be appropriate in light of the Company’s testimony that carrying costs on long-term debt would only be lower if a rate of less than 8.75% was obtained.

The Applicant also argued that the cost of the pre-payment penalties calculated at $467,000 was an 80
under-estimation as interest rates had fallen significantly since the Company had done the original calculations. NRG also noted other uncertainties, such as the terms of a new financing package and the final transaction costs.

The Applicant concluded that it would be imprudent for it to refinance at this point and that to pro- 81
hibit the Company from recovering its current cost of debt would be “an unwarranted punitive measure”. Also, NRG stated that, even if a refinancing took place, it likely could not be finalized until some time into fiscal 2004.

Board Findings 82

The Board is of the view that NRG should be able to refinance its entire debt in a manner which 83
will reduce its carrying costs even when the pre-payment penalties and transactions costs are added to the debt. With respect to NRG’s position that an interest rate of 8.75% is required to break-even and that they “are right on the edge” of a refinancing being beneficial or not, the Board sees no reason to believe that NRG cannot obtain an interest rate of better than 8.75% in the current environment. The Company’s financial position has improved greatly in the past few years. The Company is a rate-regulated monopoly with a relatively low risk. Interest rates have declined even since NRG’s preliminary discussions with two financial institutions. While, as the Applicant points out,

this leads to an increase in the pre-payment penalties, it also should mean a reduction in the new rate which NRG can obtain.

The Board accepts the position of the Company that it would not be appropriate to adjust the debt 84
rate for the 2003 test year as it will take some time for NRG to complete a refinancing. The Board is prepared to accept that the 2004 interest rate should be somewhat higher than 8% as this rate will be applied to the current forecast debt, whereas a refinancing will require NRG to incur more debt to fund the pre-payment penalties and the transactions costs. However, the Board has not factored the pre-payment penalties related to the Junsen debenture into its determinations. The Board does not believe that NRG would have agreed to the insertion of such a clause into the debenture agreement in 1998 if it had been negotiating with an arms-length third party. The Board also notes that the calculations during the hearing of carrying costs used a figure for transactions costs of $250,000 which was at the top of the range of such costs of $100,000 to $250,000 cited by NRG. The Board has also used this figure of $250,000 in making its determinations.

In light of the utility's evidence that a potential lender would be looking to re-finance its entire debt, 85
including short-term debt, the Board believes it is appropriate to deem an overall debt rate for the 2004 test year.

Based on the above, the Board deems a rate of 9.00% on all debt for the 2004 test year. 86

Return on Common Equity 87

NRG proposed a return on common equity for the 2003 test year of 9.69% based on a Long Canada 88
Bond Yield forecast of 5.96%. The proposed return on common equity for the 2004 test year was 10.02% based on a Long Canada Bond Yield forecast of 6.4%.

The proposed returns on common equity are based on the Board's Draft Guidelines on a Formula- 89
Based Return on Common Equity for Regulated Utilities and the implied equity risk premium in the returns on equity approved by the Board for the Company in its RP-2000-0126 Decision and Rate Order.

Board Staff suggested that, in light of the fact that rates for the 2003 test year are being set many 90
months into the test year, the Board may wish to consider using available actual data and an updated forecast for the 2003 test year rather than relying on the August 2002 Consensus Forecast in determining the returns on equity.

NRG argued that the August 2002 Consensus Forecast was the appropriate figure to use for the 91
2003 test year as this was in keeping with the Board's standard methodology. NRG accepted that an updated Consensus Forecast was appropriate to use for the 2004 test year.

Board Findings 92

The Board does not believe that it would be appropriate for it to depart from its established practice in setting the Long Canada Bond Yield forecast for the 2003 test year. Therefore, the Board is prepared to accept 5.96% as the forecast with a resulting return on common equity for the 2003 test year of 9.69%. 93

The Board agrees that it is appropriate to use a more recent Consensus Forecast for the 2004 test year. The Board has now reviewed the May 2003 Consensus Forecast and data on Government of Canada 10- and 30- year bond yields. Based on this information, the Board establishes 6.01% as the Long Canada Bond Yield forecast for the 2004 test year. This results in a return on common equity of 9.72% for the 2004 test year. 94

5. COST ALLOCATION AND RATE DESIGN 95

96
The Board's directive from the RP-2000-0126 Decision and Rate Order required NRG to conduct a new Fully Allocated Cost ("FAC") Study to segregate costs that relate to activities ("Ancillary Programs") that are not regulated by the Ontario Energy Board. For the purpose of this study, the Ancillary Programs include contract sales, service work, hot water heater rentals, merchandise sales and agency billing, and collection services. The study was filed in this proceeding.

97
NRG proposed to increase the monthly fixed charge for all rate classes in 2004 and decrease the second and third block (with the exception of Rate 3 Interruptible) of the distribution charge. NRG justified its proposal on the grounds that the increase in the costs associated with the fixed charge more than offset the reduction of the customer component.

98
NRG also proposed to increase the interruptible delivery commodity charge in 2004 and make changes related to the commissioning rate and to the minimum annual volume penalty rates for Rate 3 customers.

99
The charge related to the minimum annual volume penalty rate for Rate 5 customers will be changed. The proposed changes are within the established ranges.

100
The delivery sufficiency of $57,600 and $76,000 for 2003 and 2004 respectively will be used to reduce the delivery charge to those rate classes that have a revenue-to-cost ratio in excess of 1.00.

101
NRG's evidence revealed that, with the exception of Rate 3 Interruptible and Rate 5, the revenue to cost ratios resulting from the proposed rates range from 0.943 to 1.107.

102
The revenue to cost ratio for Rate 3 Interruptible is 0.355 for 2003 and 0.342 for 2004. NRG noted that if the cost of gas is included in the calculation, the revenue to cost ratio would have to be close to 0.7. NRG proposed to increase the distribution charge by 0.5 cents per cubic metre to improve the revenue to cost ratio for Rate 3 Interruptible. The Applicant also noted that it will be reviewing the application of non-coincident peak allocator to the interruptible customers prior to the next application. NRG further noted that there is only one customer in the Rate 3 class and the total annual revenue is only $8,000.

103
Board Findings

104
The Board approves the results that flow from the filed cost allocation study and the proposed rate design changes and other rate proposals, subject to the Board's findings on revenue requirement matters. The specific rates and charges that will flow from this decision will be approved in the Board's order reflecting this decision.

6. DEFERRAL AND VARIANCE ACCOUNTS 105

NRG has two gas-supply related deferral accounts and four non gas-supply related deferral accounts. 106

These accounts are: 107

- Purchased Gas Commodity Variance Account, 108
- Purchased Gas Transportation Variance Account, 109
- Regulatory Expenses Deferral Account, 110
- Direct Purchase Administration Deferral Account, 111
- Land and Building Deferral Account, and 112
- Late Payment Policy Variance Account. 113

Purchased Gas Commodity Variance Account 114

At the end of fiscal 2002, the Purchased Gas Commodity Variance Account (PGCVA) had a credit of $349,593.84. Earlier this year, NRG made two applications to adjust the commodity price of natural gas (“QRAM” applications). One purpose of these applications was to adjust the reference price used for the PGCVA. Following past practice, NRG will recover the balance in the PGCVA on a prospective basis through the gas commodity charge over a 12-month period following the effective date of the new commodity charges. No disposition of this balance is necessary as part of this proceeding. NRG proposed to continue the PGCVA in the 2003 and 2004 test years. The current reference price of $0.308133 per cubic metre, as approved in EB-2003-0061, will remain in effect until the trigger mechanism is activated. 115

Purchased Gas Transportation Variance Account 116

The Purchased Gas Transportation Variance Account (PGTVA) was created as a result of the EBRO 496 Decision with Reasons of August, 1998. In accordance with this decision, NRG split the Purchased Gas Variance Account (PGVA) into the PGCVA (commodity component) and the PGTVA (transportation component). At the end of fiscal 2002, the PGTVA had a debit of $402.41, including a credit of $9,353.64 in accumulated interest. NRG proposed to dispose of the debit balance on a prospective basis and include it as a gas transportation cost in fiscal 2003. 117

Regulatory Expenses Deferral Account 118

The balance in this account at end of fiscal 2002 was zero. NRG has recorded an expense of only $133 to this account in fiscal 2003. Because of the small balance in this account, NRG does not propose to dispose of this balance in the 2003 or 2004 test years. NRG proposed to continue the Regulatory Expenses Deferral Account in the 2003 and 2004 test years. 119

Direct Purchase Administration Deferral Account 120

This account was established as a result of the EBRO 496-02 Board Order to record revenues and expenses incurred in setting up and administering a direct purchase administration system. The balance in this account is a net debit of $8,795. NRG proposed to dispose of the balance in this account in 2003 as part of the cost of service. In addition to the disposition of the debit balance in this account, NRG proposed to include the revenue from the direct purchase administration fee as a credit to the cost of service in fiscal 2003 and 2004. NRG proposed to close this account in 2003. 121

Land and Building Deferral Account 122

This account was established in the RP-2000-0126 Decision and Rate Order. The balance at the end of fiscal 2002 was a debit of $753,281. NRG proposed to transfer this balance to rate base effective October 1, 2002, and to close this account. 123

Late Payment Policy Variance Account 124

Because of difficulties related to quantifying delayed payment revenues NRG has not attempted to calculate the balance in this account. NRG proposed to close this account without any disposition. 125

Board Findings 126

The Board accepts the Company's proposals with respect to deferral and variance accounts. 127

7. REVENUE SUFFICIENCY/DEFICIENCY AND RATE ORDER 128

Based on existing rates and NRG's proposals, the Company calculated a gross revenue deficiency of $498,168 for fiscal 2003 and a gross revenue sufficiency of $153,485 for fiscal 2004. Netting out the gas commodity component, the delivery-related component is a revenue sufficiency of $57,600 for fiscal 2003 and $76,000 for fiscal 2004. 129

The Company proposed that only the delivery component of the rate structure be changed to reflect the revenue sufficiencies. The gas commodity revenue sufficiency or deficiency would be reflected in the quarterly rate adjustment mechanism process adopted by the Board. 130

Since the rate changes for the 2003 fiscal year were anticipated to occur at the beginning of the fiscal year, the Company proposed a one-time adjustment to customer bills. 131

The Company's proposed revenue deficiency/sufficiency is adjusted to reflect the following Board findings contained in this decision. 132

- Lower regulatory expenses of $13,750 for each of fiscal years 2003 and 2004; 133
- A lower rate base and revenue in fiscal 2004 due to the non-approval for ratemaking purposes of the Norfolk East project; 134
- Lower overall cost for debt for fiscal year 2004; and 135
- A lower rate for common equity for fiscal year 2004. 136

The Board also found that half of the $88,710, or $44,355, in capital gains on the sale of NRG's old building facilities be credited to customers. 137

The Company is directed to submit with dispatch to the Board a draft rate order, with appropriate documentation, containing the following: 138

- Financial schedules for each test year reflecting the Board's findings in this decision, ie. Rate Base, Utility Income (including income tax calculations), Capitalization/Cost of Capital, Determination of Revenue Sufficiency/Deficiency. 139
- Rate schedules for each of fiscal years 2003 and 2004 flowing from the above calculations and other Board findings in this decision. 140

- One-time adjustments to customer bills flowing from the later implementation date than October 1, 2002 for the new 2003 rates, the clearing of deferral/variance accounts, and from sharing the capital gains. 141

- A list of deferral/variance accounts approved for fiscal years 2003 and 2004. 142

- Notices to customers to accompany the first bills reflecting the new rates and bill adjustments. 143

DATED at Toronto June 27, 2003 144

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Paul Vlahos
Presiding Member
On behalf of the Hearing Panel