RP-2004-0167
EB-2004-0253

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

AND IN THE MATTER OF an application by Natural Resource Gas Limited for an Order or Orders approving or fixing just and reasonable rates for the 2005 fiscal year commencing October 1, 2004.

BEFORE: Jan Carr
Presiding Member and Vice Chair

Paul Vlahos
Member

DECISION WITH REASONS

December 20, 2004

1. THE APPLICATION AND THE PROCEEDING

1.0.1 Natural Resource Gas Limited ("NRG", the "Utility" or the "Applicant"), filed an application dated June 24, 2004 (the "Application") with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act*, *1998,* S.O. c.15, Sched. B, as amended, for an order or orders of the Board approving or fixing rates for the 2005 fiscal year, commencing October 1, 2004.

1.0.2 The Board issued a Notice of Application, dated July 13, 2004, along with directions for service of the Notice. Only Union Gas Limited ("Union") intervened.

1.0.3 The Board issued an Interim Rate Order and Procedural Order No. 1 on August 9, 2004. Through this instrument the rates were made interim effective October 1, 2004, an interrogatory process was provided for and the date of the commencement of the oral hearing was set for October 13, 2004. On August 13, 2004 the Board issued Procedural Order No. 2, changing the date of the commencement of the oral hearing to Thursday, October 14, 2004. The hearing concluded on Friday, October 15, 2004, with Board staff's oral submissions. NRG filed written argument on October 28, 2004.

1.0.4 The Utility was represented by counsel Scott Stoll and Peter Budd. The Board's legal counsel were Michael Lyle and Michael Millar. Union did not attend the hearing and did not make any submissions. Counsel to NRG called as witnesses Bill Blake, the Utility's President and General

Manager, Sandy McCallum, the Utility's Financial Manager, and Randy Aiken, a Principal with Aiken and Associates.

1.0.5 NRG's updated evidence indicates a gross revenue sufficiency of $297,600 for the 2005 fiscal year if rates are not changed. This Decision concerns NRG's projected revenue deficiency associated with distribution and other matters.

1.0.6 Copies of all the evidence, exhibits and submissions in this proceeding, together with a verbatim transcript of the hearing, are available for public review at the Board's offices. The Board has considered the full record of this proceeding but has only referenced it to the extent necessary to provide context for its findings.

1.0.7 The remainder of this Decision deals with the test period of the filing, specific components of NRG's revenue requirement and adjusts the claimed revenue deficiency. The Decision also deals with cost allocation and rate design, disposition of deferral accounts and implementation matters.

2. TEST PERIOD

2.0.1 In its previous decision dealing with NRG's 2004 rates (RP-2002-0147/EB-2002-0446), the Board suggested that NRG consider a three year rate filing. In that decision the Board recognized the increased forecasting risk associated with a longer test period and expected that the risk would be more than offset by the savings in regulatory proceedings. The Board stated that it would welcome a filing for a three year test period in NRG's next rates case. It directed Board staff to discuss implementation issues arising from a move to a three year test period with the Utility and to report back to the Board by the end of 2003.

2.0.2 NRG indicated that its decision to file a one year test period in the instant proceeding was based on the uncertainty surrounding the tobacco industry and its expectation that a one year test period filing would return the Utility to an appropriate filing schedule.

2.0.3 NRG provides significant amounts of gas, and associated services, to tobacco related customers. For 2005, NRG projected that approximately 23% of its throughput and 13% of distribution revenues will be tobacco related. NRG stated that Imperial Tobacco recently indicated that it may not continue to purchase locally grown tobacco in the future. The Utility testified that this introduces a new source of uncertainty into NRG's forecast of Rate 2 gas consumption.

2.0.4 The Utility estimated that a decision by Imperial Tobacco not to purchase any locally grown tobacco would lead to a "catastrophic" decline in tobacco production. The Utility estimated that such an event would reduce Rate 2 customers' gas consumption to about half the projected level.

2.0.5 The amount of tobacco purchased under quota has diminished every year since 1998; for 2005 it is projected to be about half the amount it was only 7 years ago. The witnesses testified that this uncertainty has existed for several years and that NRG has coped with considerable declines in tobacco production levels to date. The Utility testified that there are other sources of tobacco related risks, such as mould or early frost, and that these risks remain whether a one year or a three year forecast is required. While the production quota is normally set in January, this year it was set in May. Thus, for four months, NRG did not have the data it normally relies on to forecast the gas to be used by its Rate 2 Seasonal customers.

2.0.6 Board staff characterized the timing of the subject Application relative to the previous application as a risk mitigation mechanism and suggested other mechanisms are possible that may allow the filing of a multi-year test period rate application while addressing the concerns of the Utility. Examples of such alternatives included a special in-period filing for relief styled after the Z-factor mechanism of PBR plans or protection through a variance account for lost revenue. Board staff suggested that the Board re-issue its direction to staff to work with the Applicant on approaches that will reduce the regulatory costs passed on to the customers.

2.0.7 The Applicant indicated it is open to relying on a written process to deal with future claims or greater use of deferral or variance accounts as ways to mitigate or control regulatory costs. The Utility also indicated that it is willing to consider applying for a longer test period in future years if it can be satisfied that there was an appropriate mechanism in place to address its concerns about risk.

Board Findings

2.0.8 The Board notes that in fiscal 2005 the regulatory cost per customer amounts to approximately $17.50. The Board continues to be concerned with this financial burden imposed on ratepayers and the use of the Board's resources. The Board re-directs its staff to work with the Utility to identify, scope and propose ways to reduce the regulatory burden incurred in setting rates. The Board notes that the previous application concerned two test years and, accordingly, expects that a multi-year test period will be among the alternatives evaluated. The Board directs the Utility to file a report documenting all available alternatives that reduce regulatory burden or support a multi-year test period, or both. This report is to be filed no later than January 31, 2005. The report must include an implementation plan for the preferred alternative - including a proposed filing schedule that would provide the Board with sufficient time both to complete an appropriate regulatory review and to set rates on a prospective basis. Board staff and the Utility are expected to be diligent and to commence this work immediately upon this Decision being issued.

3. REVENUE REQUIREMENT

3.0.1 NRG projected that it will incur $10,119,931 of costs to provide gas, gas delivery service and ancillary programs to its customers in the 2005 test year. More than two-thirds of these costs relate to commodity supply. The remaining costs are attributable to NRG's proposed cost of service and proposed cost of capital. Based on current rates, NRG claimed a revenue deficiency of $297,600 for the test year.

Cost of Service

3.0.2 The issues related to the cost of service in this proceeding are:

- legal expenses;
- depreciation expenses.

Legal Expenses

3.0.3 NRG originally forecast $15,000 of legal expenses for 2005; this was updated to $190,000. The $175,000 increase was solely attributable to the anticipated legal fees to appeal the Board's decision in RP-2002-0147/EB-2004-0004. NRG previously applied to recover unrecorded gas commodity related costs on a retroactive basis through its Gas Purchase Rebalancing Account; the Board denied that application. Subsequently, NRG re-applied and was successful, except that the Board did not allow interest to accrue on the uncollected balance. Through the appeal NRG seeks to recover any and all interest and regulatory costs associated with the unrecorded costs addressed in the cited decision. The Utility's factum discloses that it estimates the minimum interest costs at $95,701. The Applicant expected that the appeal hearing will take one or two days.

3.0.4 The cost of the appeal was determined by NRG's management and its counsel for the appeal. The Utility stated it believed the budgeted expense to be reasonable but was not able to describe or quantify the relief being sought by the appeal. An amount of $50,000 was billed in fiscal 2004, of which $30,000 was paid. The Utility conceded that such out-of-period expenses are not normally carried forward. However, it suggested that because this amount was part of an ongoing cost it might be appropriate to deal with the entire cost of the appeal in the test year.

3.0.5 Board staff asked whether a deferral account could be used to track the monies spent on the appeal. The Utility stated that it had not considered this proposition carefully. Board staff submitted that the Board may wish to treat the expense in two ways: by establishing a deferral account to accrue the legal expenses of the appeal as they are incurred; or by denying recovery of this expense through rates.

3.0.6 In its argument, NRG submitted that the $175,000 would be a properly incurred cost, and should be included in the cost of service recovered through rates. NRG further submitted that if the Board did not agree with its position that it would be appropriate to create either a variance or deferral account.

Board Findings

3.0.7 The Board will not allow the legal expense incurred by NRG in its appeal of Board decision in RP-2002-0147/EB-2004-0004 to be recovered from its ratepayers. The Utility's return on equity compensates the Utility for the risks it incurs - including regulatory risk. This appeal was launched at management's discretion and solely for the benefit of its shareholder. It is inappropriate for ratepayers to support legal actions that, if successful, will benefit the Utility's shareholder exclusively.

3.0.8 By way of comment, $50,000 of legal expenses has already been invoiced in the prior fiscal year. NRG ought to be aware that its proposal to include this amount in the test year for this Application represents a request for relief for costs incurred out-of-period and therefore would not be recoverable through rates. Further, the Board questions the prudence of a decision to spend $175,000 for a potential recovery of up to about half that amount. Finally, the Board questions the size of the claimed legal expenses for an appeal the Applicant expects to last no more than two days.

Depreciation

3.0.9 NRG's projected depreciation expense for 2005 is $677,250; it is $120,975 more than the amount projected for 2004. Approximately one-third of the increase is attributable to a proposed increase in the rate base, the remainder is due to changes in depreciation rates recommended by a recently completed depreciation study.

3.0.10 NRG noted that depreciation studies are generally updated every five years and that its previous depreciation study was done some seven years ago. The current study uses the same methodology as did the previous study and relies on current NRG data, as well as the findings of Enbridge Gas Distribution Inc.'s ("Enbridge") and Union's depreciation studies, to estimate the applicable depreciation rates. The Utility was not able to comment either on the contents of Enbridge's and Union's depreciation studies or on how the methodologies used by Enbridge and Union support the findings of their respective depreciation studies.

3.0.11 NRG's depreciation study proposes changes both to the depreciation rates for most asset classes and to the depreciation method for three asset classes. NRG proposes to change the depreciation method for computer hardware and computer software from straight line to declining balance. The Utility also proposed to change from depreciating franchises in aggregate to depreciating each over its life.

3.0.12 In its submissions, Board staff suggested phasing in the findings of the depreciation study, if there were concerns of rate shock. NRG stated that it did not anticipate any rate shock attributable to implementing the study's findings and concluded that there is no need for phasing in. NRG further stated that there were two harms to delaying the implementation of the study: firstly, rates charged to customers will be higher because the higher level of undepreciated assets will attract return; and secondly, when new depreciation rates are implemented in future, they will be applied to higher undepreciated asset values and, again, rates charged to customers will be higher than they would be otherwise.

Board Findings

3.0.13 The Board accepts the results of NRG's depreciation study for the purposes of determining the depreciation expense to be recovered through rates. The Board is satisfied that there is no need for phasing in the results of the depreciation study.

Rate Base

3.0.14 NRG projected that its rate base will amount to $9,411,246 in 2005. This is approximately $30,000 less than the year before; the decrease is attributable to the findings of both the Working Cash and Depreciation studies filed in this proceeding and to changes in capital spending. NRG expected to spend $863,324 on capital in fiscal 2005. NRG also proposed to cease capitalizing its meter maintenance costs and, instead, to expense them. With respect to rate base, at issue in this proceeding is the reasonableness of the proposed capital budget and the appropriateness of the proposed change to NRG's accounting policy for meter maintenance costs.

Capital Budget

3.0.15 In its June 23 filing, NRG projected $875,783 of capital spending in fiscal 2005; this was updated on October 5 to $863,324. The change is the net of: deferred spending on an automated meter reading system, $230,000; identification of eight new expansion projects, $144,722; increased spending on Service Additions, $23,000; and increased spending on automobiles, $65,000.

3.0.16 The witnesses confirmed that one of the eight new projects, Springwater Road north from Jaffa, costing $15,987, had in fact been deferred from 2004 to 2005; the remaining projects were identified by August of this year and often in response to inquiries from local area residents. The Guysborough West County Road 55 project, costing $20,293, will serve a tobacco farm, 15 homes and one commercial customer; NRG forecasts the project's benefit-to-cost ratio at 2.04. The proposed County Road 45 - Mt. Salem to Calton project, costing $37,024, will also serve a tobacco farm, as well as a grain dryer and 25 homes; its benefit-to-cost ratio is projected at 1.87. The County Road 55 East to Houton Centre and north project (costing $29,517) is largely to serve tobacco related loads and includes 25 homes and 2 commercial operations, its benefit-to-cost ratio is forecast at 1.89.

3.0.17 Two new Rate 2 Seasonal customers are to be added in 2005, both in tobacco related businesses. The witnesses testified that the company does not expect to lose any of its Rate 2 customers in the test year period.

3.0.18 The prefiled evidence shows that in 2003 NRG spent $1,154,108 on capital and that the Board approved rates for that year were premised on a spending level of $1,341,050. The Utility testified that no substantial or major changes have been made to NRG's capital spending forecasting process. The Utility stated further that customer attachments depend on movement in prices of alternate fuels and the Mains Additions and

Replacements projects proposed have an aggregate benefit-to-cost ratio greater than 2.

3.0.19 The Utility confirmed under cross-examination that, for the period 1998 - 2003, the cumulative difference between the level of capital spending approved by the Board when establishing rates and the actual capital spending of the utility was an under expenditure of $927,668. The Utility confirmed that for 2003 not all planned line additions were executed. The Utility also accepted that the underspending in 2003 implies that the utility over-collected, all other things being equal, approximately $20,000 from its ratepayers.

3.0.20 Board staff did not comment on any individual component of the proposed capital budget. Rather, staff suggested that the Board cannot have confidence that the utility will not underspend versus its filed capital budget in 2005. Accordingly, Board staff proposed a reduction of 20% - 40% of the planned spending on Mains Additions and Replacements.

3.0.21 In its response, NRG indicated that in the most recent four years, it has overspent on some capital components from the levels approved by the Board but spending on mains additions has been between 70% and 142% of the Board approved level.

Board Findings

3.0.22 The Board finds that NRG has exhibited an ongoing pattern of spending less overall on capital projects than was included in the forecasts which the Board relied on when setting rates.

3.0.23 The Board is concerned that the Applicant identified the relatively large number of new projects that it did as late as it did in the evidence submission process. The Board acknowledges that the timing of a customer's attachment is, ultimately, at the Utility's discretion. The Board notes that in its previous application, NRG stated that the Utility was entering a mature phase of operations and that the annual capital spending would be approximately $600,000. The Board recognizes the ongoing pattern of underspending and, guided by past evidence, sets the capital spending level at $600,000 for purposes of setting 2005 rates.

3.0.24 The Board will not decide which components of the capital budget are to be reduced and in what amount; rather, for the purposes of setting rates, the Board requires that each component be reduced in the same proportion as the overall reduction.

Meter Maintenance Accounting Policy Change

3.0.25 Prior to 2003, NRG capitalized meter maintenance costs. In 2003, the Utility began to expense these costs. In this Application NRG seeks to have this accounting change recognized for the purposes of determining the revenue requirement. In 2005 this results in Operations and Maintenance costs being $53,000 higher than they would otherwise be and rate base being lower by a similar amount.

Board Findings

3.0.26 The Board notes that this change is consistent with the Board's Uniform System of Accounts for Class A Gas Utilities and accepts the rate making implications resulting from this change.

Cost of Capital

3.0.27 In its previous application NRG proposed an 11.38% cost of long term debt and a 6.17% cost of short term debt, for its 2003 test year; it relied on 11.60% and 7.52% respectively for its 2004 test year. The Board accepted NRG's cost of debt for 2003 and deemed an overall cost of debt of 9.00% for 2004. In deeming the debt rate for 2004, the Board relied on the Applicant's evidence of the possible outcomes of the refinancing discussions then underway and on its estimate of the fixed costs of refinancing.

3.0.28 The Board has established NRG's rates using a hypothetical capital structure of 50% equity and 50% debt for many years. As the Utility's reported debt is less than 50% the Board imputes unfunded debt in an amount that achieves this level.

3.0.29 In 2004, 27 Cardigan Inc., an affiliate of NRG, sold its NRG debt to Banco Securities Inc. for the face value of the debt. NRG projects that at the end of its 2005 fiscal year its debts will consist of:

- a loan from the Imperial Life Assurance Company at 11.80%, $1,615,977 outstanding, due in 2009;

- a loan from Banco Securities Inc. at a minimum 9.25% interest rate, $951,000 outstanding, eligible for repayment upon payout of the Imperial Life loan and due in 2010;

- a debenture from Banco Securities Inc. at 11.03%, $156,994 outstanding, due in 2009

- a demand debenture payable monthly at the floating prime lending rate for Canadian dollar demand commercial loans plus 1.5%, $118,007 outstanding.

3.0.30 According to the updated evidence, the deemed unfunded debt for the test year is $1,863,645. This number will be lower as a result of the findings of this Decision.

3.0.31 NRG's original 2005 rates filing was based on an overall cost of debt of 9.00%; this was later updated to 9.20%. In response to questioning from Board staff, the Applicant testified that the Board's decision in RP-2002-0147 was interpreted as tying the Utility's debt rate to long term interest rates, in the same way that the Board's formula for determining the return on equity operates.

3.0.32 To date, NRG has not refinanced its debt. The witnesses testified that the Utility will discuss refinancing with lenders over the next several months. These discussions may be completed in February or March, 2005. NRG testified that these lenders are concerned about the Utility's risk arising from its dealings with tobacco related customers. To assist the prospective lenders in establishing and understanding the amount to be loaned, the Applicant is preparing a five year capital forecast. The witnesses testified that the Utility has not needed additional funding in the past 12 months.

3.0.33 At the time of the hearing, NRG anticipated it may be able to negotiate an interest rate in the 8% range, depending on the amount loaned, the covenants given and other factors. In response to Undertaking J1.5, NRG quantified the interest payable in fiscal 2005, assuming that refinancing occurs and this rate is achieved, at $282,800. The total carrying cost of debt, including the cost of unfunded debt, amounts to $349,830.

3.0.34 The previous decision considered the prospect and benefits of refinancing the Utility's debt in some detail. While refinancing did not occur, 27 Cardigan Inc. sold the NRG debt it held to Banco Securities Inc. ("Banco"). The Utility's President appeared to have scant knowledge of this new lender but believed it to be an unrelated, at-arm's-length third party. In response to two undertakings, the Utility stated that the debt was sold at face value and provided Banco's mailing address and the name of its President.

3.0.35 Board staff noted that if the Utility pays out its existing debt the incurred interest expense will decrease and the unfunded debt component of the capital structure will increase. Board staff suggested that for 2005, the Utility's long term debt rate could be set at 8% and, based on the prime rate being 4.00% to 4.25%, the short term debt rate could be set at 5.5% or 5.75%. Board staff noted that the Utility's financial stability has improved and that the Board may wish to direct the Utility to file a study on this matter with its next rate application.

3.0.36 In its reply argument, NRG clarified that if all the deemed debt were to be refinanced the Utility would have surplus cash and that prospective lenders are interested in how this cash may be used. Under this scenario, the interest expense for 2005 could amount to $349,830 or 7.43% overall. NRG argued that it was inappropriate to evaluate the benefits of refinancing over the short term. It emphasized this point by its estimate of the short-term savings of refinancing, $49,446, versus the incremental interest and financing charges for the period 2006 - 2016 of refinancing, $550,000.

3.0.37 The Utility argued that the Board should direct a study of the deemed capital structure if it wishes to address the issue.

Board Findings

3.0.38 The Board does not accept the Utility's request for the use of a deemed debt rate of 9% or 9.2% in calculating its revenue requirement. The Board does not intend to tie the Utility's debt rate to the fluctuations of long term interest rates at this point in time. The Board, in its prior decision, set a deemed debt rate in light of the evidence before it that the Utility would be able to reduce its interest expense if it re-financed its existing debt and the fact that much of the Utility's debt was held by an affiliate.

3.0.39 The Board is concerned about the lack of knowledge exhibited by the President of the Utility as to the identity of a major creditor of the Utility, Banco Securities Inc. The Utility has not brought forward requested evidence to demonstrate that Banco is an unaffiliated, arm's length party. Thus, there remains no evidence from an actual transaction demonstrating the interest rate that NRG could obtain in the open market.

3.0.40 The Board has heard evidence in this proceeding that the Utility could refinance its debt at an interest rate of approximately 8% and that there would likely be associated penalties and transaction costs ("breakage costs"). The Board will adopt a deemed long term debt rate for the 2005 fiscal year of 8%. The Board will consider the prudence of breakage costs if and when they are incurred. At that time, the Board will also address the recovery of any breakage costs through rates.

3.0.41 The Board sets NRG's cost of unfunded short term debt at 5.5%, which reflects 150 basis point premium over forecast prime of 4.00%.

3.0.42 The Board accepts NRG's proposed return on equity of 9.57%.

4. DEFERRAL ACCOUNTS

4.0.1 NRG has the following four Board-authorized deferral accounts:

- Purchased Gas Commodity Variance Account (PGCVA)
- Purchased Gas Transportation Variance Account (PGTVA)
- Gas Purchase Rebalancing Account (GPRA)
- Regulatory Expenses Deferral Account (REDA)

4.0.2 These accounts earn simple interest at the Board approved short-term interest rate. NRG proposes to change the rate used to calculate interest on deferral and variance account balances; instead of using the Board approved short term debt rate for the duration fo the test period it will use the prime rate, as observed on the first day of each quarter, plus 150 basis points.

4.0.3 The PGCVA and the GPRA are cleared quarterly through the Quarterly Revenue Adjustment Mechanism. The PGTVA and the REDA are dealt with in the rates cases. The balances in both accounts have been determined in the same manner as in the past. The REDA is projected to have a debit balance of $149 at the end of fiscal 2005; NRG proposes to carry this balance forward.

4.0.4 The PGTVA is projected to have a debit balance of $30,415 at the end of fiscal 2004. This amount is the difference between the forecast average transportation cost, $0.020584/m^3, and the actual average transportation cost incurred. For 2005, NRG proposes to increase the reference price used when calculating the balance recorded in the PGTVA to $0.021848/m^3.

4.0.5 NRG has requested permission to establish a new variance account, the Gas Cost Difference Recovery Variance Account ("GCDRVA"). In RP-2002-0147/EB-2002-0004, the Board authorized NRG to collect $531,794 from its system gas customers over three years in equal amounts each year. The requested variance account will accumulate the difference between the amount collected from ratepayers and $177,265. This amount being one-third of the original amount to be recovered. This balance will be posted for disposition in the subsequent year.

Board Findings

4.0.6 The Board authorizes the establishment of the GCDRVA with interest to be applied in the same fashion as the other deferral accounts. The Board also authorizes the proposed adjustment to the PGTVA reference price for 2005. The draft rate order to be filed by NRG must incorporate the recovery of the 2004 PGTVA balance.

5. COST ALLOCATION AND RATE DESIGN

5.0.1 NRG seeks to revise two components of its Comprehensive Cost Allocation study and to update three others. The effect of changing the insurance functionalization factor and the regulatory functionalization factor is a redistribution of the $265,000 of forecast insurance costs and of the $108,500 of forecast regulatory expenses among the utility's six functions, specifically assigning some of these costs to the Utility's Gas Supply function. NRG has recalibrated its coincident peak demand allocator, non-coincident peak demand allocator and the zero intercept analysis relied on to classify mains using current data.

5.0.2 These changes are revenue neutral. The Rate 1 customers are affected most. The residential customers' cost responsibility decreases by $33,900 (or $6.05 per customer) while commercial customers' cost responsibility increases by $12,300 ($32.11 per customer) and industrial customers' cost responsibility increases by $12,100 ($257.45 per customer). Rate 3 Firm customers cost responsibility increases by $11,900.

5.0.3 NRG proposes to increase the monthly fixed charge for all rate classes, except Rate 4; to increase the delivery charges for all rates classes; and to increase the demand charge for Rate 3. In its original evidence, NRG proposed to increase the volumetric rate applied to its 2nd block, but in its update chose to increase the volumetric rate applied to the 1st block. These changes flow from the cost allocation changes, are consistent with other utilities increased reliance on fixed charges and support the recovery of the proposed revenue deficiency. The proposed changes alter NRG's projected revenue-to-cost ratios so that except for Rate 3 Interruptible customers, they are within 500 basis points or less of unity.

5.0.4 The Utility testified that its preference is to give priority to changing the fixed charge when implementing the proposed changes. If the Board determines that the deficiency is smaller than that claimed in the Application, the Applicant prefers to preserve the proposed change to the fixed charge and implement a correspondingly smaller change in the variable charge.

5.0.5 NRG also proposed to increase the "system gas fee" component of the gas supply charge from the current level of $0.000354/m^3 to $0.001159/m^3.

Board Findings

5.0.6 The Board accepts NRG's proposed changes to its cost allocation study and system gas fee. The Board accepts NRG's changes to its rate design since they will more closely align cost recovery with cost causality. The cost allocation and rate changes shall reflect the lower deficiency resulting from the Board's findings, as proposed by the Utility.

6. IMPLEMENTATION

6.0.1 This Decision is rendered mid-way through NRG's test period. In the past, when rate changes have been implemented during the period, NRG has billed each customer a lump sum based on the cumulative difference between the amount billed under the old rates and that billed under the new rates.

6.0.2 The Board is concerned with retroactivity, regardless of how it arises. Retroactivity is of particular concern when it involves cost reallocations among rate classes and rate redesign. In this case, NRG was late in filing and its proposals involve some degree of cost reallocation. The Board considered allowing the rates to be changed only on a prospective basis, without reflecting lost revenue, but opted at this time to only provide a warning to the Utility. In the future, if a decision is rendered during the test period because of delays attributable to the Utility, NRG should not expect to recover the full revenue deficiency.

6.0.3 The Utility noted that changing the fiscal year-end to June 30 may be a consideration since it would allow rate changes to be implemented during the utility's low throughput period and would reduce the likelihood of large fixed sums being charged, or refunded, to ratepayers. Also, NRG confirmed that its billing system does not have the ability to incorporate rate riders. Further, its billing system cannot pro-rate, that is, apply two different rates in the same billing period. On the last point, the Utility confirmed that, assuming rates increase, the Utility will over-earn in the billing period when new rates are implemented since the Utility uses the new higher rates for the entire billing period. The Board expects that discussion between the Utility and Board staff on the regulatory framework to apply to NRG will include consideration of proposed resolutions of these matters.

6.0.4 NRG shall promptly file with the Board a draft rate order to give effect to the Board's findings and directions herein for implementation effective October 1, 2004. This draft rate order shall recalculate the revenue deficiency, which as a result of this Decision will be lower than the amount claimed, and present it in the form of schedules showing Utility Income, Rate Base, Capitalization and Cost of Capital, and Determination of Revenue Deficiency/Sufficiency. These schedules shall depict the proposed amounts, the Board's adjustments, and the resulting amounts. NRG shall include appropriate support schedules and explanations. For examples of such presentation, NRG should review previous main rate decisions by the Board for NRG and the other two gas distributors.

6.0.5 The Capitalization and Cost of Capital schedule shall show the long term debt amount, the short term debt amount, the common equity amount at 50% of the Board approved rate base and the unfunded debt amount to equate capitalization with rate base. As found earlier, the cost of long term debt shall be 8.0% and the cost of unfunded debt and short term debt shall be 5.5%. The rate of return on common equity shall be 9.57%.

6.0.6 The reduction in capital expenditures will affect rate base (net plant, cash working capital requirement) and net utility income (revenue, depreciation, income tax provision). NRG shall provide sufficient explanations for the Board to review the impacts on the above items, and ultimately, Net Utility Income and Rate Base.

6.0.7 The filing shall include appropriate notices to customers. It is the Board's intention to implement the changes in rates arising from this Decision with the changes that will arise from the disposition of NRG's recently filed Quarterly Review Adjustment Mechanism application.

NRG shall file a draft rate order that combines the rate changes from this Decision and the decision in the Quarterly Review Adjustment Mechanism proceeding.

DATED at Toronto, December 20, 2004.

Original signed by

Jan Carr
Presiding Member and Vice Chair

Original signed by

Paul Vlahos
Member