EB-2005-0544

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 Natural Resource Gas Limited, pursuant to section 36 (1) of the *Ontario Energy Board Act, 1998,* for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission, and storage of gas as of October 1, 2006;

BEFORE: Gordon Kaiser
Vice Chair and Presiding Member

Cathy Spoel
Member

DECISION WITH REASONS

September 20, 2006

BACKGROUND

Natural Resource Gas Limited ("NRG" or the "Applicant"), filed an application dated March 30, 2006 with the Ontario Energy Board under section 36 of the *Ontario Energy Board Act*, *1998,* S.O. c.15, for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas for the 2007 fiscal year, commencing October 1, 2006.

NRG is a privately owned utility that sells and distributes natural gas within Southern Ontario. The utility supplies natural gas to Aylmer and surrounding areas to approximately 6,500 customers with its service territory stretching from south of the 401 to the shores of Lake Erie, from Port Bruce to Clear Creek. A color coded map showing NRG's franchise area appears in Schedule A of this decision.

The Board issued a Notice of Application, dated April 13, 2006. Only Union Gas Limited ("Union") and Integrated Grain Processors Co-operative (IGPC) intervened. On May 26, 2006, the Board issued Procedural Order No. 1, establishing the procedural schedule for all events up to and including the oral hearing, which was scheduled to commence on July 24, 2006. The Board also ordered a Public Forum to be held in Aylmer on July 18, 2006, to provide NRG ratepayers an opportunity to voice their concerns, seek information, comment or ask questions related to services provided by NRG. The Company was required to attend this event and respond to questions posed by ratepayers. A Draft Issues List was attached to the Procedural Order.

NRG in this application forecasts a revenue deficiency of $135,879 for the 2007 fiscal year. This will result in an annual increase of approximately $4 or one percent to a typical residential customer's annual distribution charge. A typical Commercial customer will see no change while a Rate 1 Industrial customer will see an annual increase of $380 or 11 percent. A typical Rate 2 seasonal customer will see an increase of $504 or 22 percent to their annual distribution charge.

For reasons which follow, the Board grants the requested relief in part. The adjustments to the requested costs are summarized in Schedule B.

THE PUBLIC FORUM

A Public Forum to allow NRG ratepayers to voice their concerns was held in Aylmer on July 18, 2006. NRG participated and was represented by Mr. Mark Bristoll, the Chairman of NRG. The Mayor of Aylmer participated and expressed his appreciation to the Board for holding the hearing within the local community. He did not consider NRG's requested rate increase inappropriate but was concerned about NRG's ability to serve large industrial customers.

Mr. Bristoll indicated that NRG had received a request for significant new industrial load by a proposed ethanol plant. The Mayor wanted NRG to explore the possibility of building a larger pipe than that required to serve the ethanol plant so as to create additional capacity for future customers.

The proposed ethanol plant in the town of Aylmer is an initiative of a 650-member co-operative of southern Ontario corn producers. The $90 million plant will have a production capacity of 150 million litres of ethanol per year and will employ 35 people. The plant is estimated to consume 220 gigajoules of natural gas an hour and could add 50 to 60 million cubic meters to NRG's throughput volume. This would triple NRG's current throughput.

The panel asked NRG to comment on the status of the proposed ethanol plant. NRG indicated that IGPC, the owner of the ethanol plant was in the process of completing environmental assessments and that NRG expects to make a "Leave to Construct" application in the near future. The Mayor expressed concern that construction may not proceed in time to meet the requirements of IGPC. The mayor indicated that the financing of the project was dependent on the availability of required quantities of natural gas to the proposed plant in a timely manner. NRG promised full co-operation and stated that it is a community-based utility dedicated to its growth. Mr. Bristoll continued that NRG would be applying to the Board for the necessary "Leave to Construct" once negotiations with IGPC were completed.

Other issues brought forward by local residents included the difference in rates between Union and NRG, delays in switching to gas marketers and safety issues with respect to installing water heaters.

Some residents complained that NRG's rates were higher than Union's and provided recent bills to demonstrate their point. NRG responded that its average consumption per customer is considerably less than Union's. This was true across the different categories of customers and this resulted in higher operating costs per customer. In addition, NRG noted that its system was newer than Union's and therefore the capital cost for each cubic meter of gas was higher.

One customer expressed her frustration over the fact that her account has still not been moved to a gas marketer. The Company agreed that they have been slow and promised to switch all contracts within 60 days. NRG also provided a list of direct marketers that customers could switch to if they wish.

A safety concern was also brought to the attention of the Board by a customer of NRG. It was related to installation of rental hot water tanks and the customer claimed that NRG allowed self or private installation of hot water tanks. The Company disputed this claim and promised to investigate this particular incident that the customer brought to their attention.

NRG responded to customer concerns about difference in rates between Union and NRG at the oral hearing in Toronto and provided a detailed explanation. NRG's analysis indicated that its cost of providing gas to a residential customer is approximately 20% higher than a customer in Union's southern operations area and 8% higher than a customer in Union's eastern operations area. With respect to NRG's seasonal customers such as tobacco curing customers, the cost is 17% higher than for a similar Union customer.

The Company provided a number of reasons for the difference as outlined below:

- The volumes consumed by an average NRG customer are considerably less than the volumes consumed by an average Union customer. This is true for all classes of customers and essentially makes the NRG system a more costly system to operate.

- NRG has a higher return on equity as compared to Union.
- Union has embedded debt costs of 7.68% in its rates as compared to NRG's total debt cost of 8.45%.
- NRG has a relatively new rate base as compared to Union. This means that its meters, regulators and mains have not depreciated to the same extent as Union's. In other words, NRG is carrying a higher net book value in its rate base.
- NRG's franchise area is essentially rural with no urban centres while Union has large urban centres in its Southern Operations Zone including Hamilton, London and Windsor. This means that NRG has to put more pipes in the ground to get to the same number of customers. This is one of the reasons why Union's other operating areas that are sparsely populated reveal smaller differences in rates when compared to NRG.

Board Findings

The Board recognises and appreciates the concerns raised at the Public Forum by local residents and customers of NRG.

With respect to differences in rates between Union and NRG which was raised at the town hall meeting, the Board instructed NRG to provide an analysis. That analysis[1] explains the differences to the satisfaction of the Board. There are significant differences in operating costs which flow directly from the nature of the territory in which the two companies operate. Essentially NRG enjoys smaller economies of scale than Union. NRG also has newer plant and therefore higher level of capital costs including a higher level of equity and debt.

The Board is concerned about customer complaints that NRG delays moving customers from system gas to direct purchase. The Company has provided assurances to the Board that they are committed to completing the process within 60 days. The Board

[1] See transcript EB-2005-0544 volume 2, pages 103-108

urges any customers who experience difficulty switching their accounts to direct purchase to contact the Consumer Relations Centre of the Ontario Energy Board.

With respect to the new ethanol plant, the Board recognises that this is a major opportunity for both NRG and the town of Aylmer. The Board urges NRG to co-operate with the town and IGPC to the maximum extent possible, in order to ensure that negotiations proceed in an efficient and timely manner. The Board orders NRG to provide a monthly update to the Board on the status of its pending “Leave to Construct” application with respect to the proposed ethanol plant.

The Board further directs NRG to consider the economic feasibility of adding a larger pipeline than that required to accommodate volumes associated with the proposed ethanol plant. The mayor has indicated that this will help attract additional industries and mitigate the local impacts caused by falling tobacco production and the closing of the Imperial Tobacco plant in Aylmer. NRG should look into the possibility of adding additional capacity as long as it does not cause undue burden on existing rate classes or significant cost overruns for NRG and IGPC. Such a study must be filed with the “Leave to Construct” application.

RATE BASE

NRG's updated evidence indicates that its rate base will amount to $9,693,286 in 2007. This is $234,154 more than 2006 forecast and $421,792 more than the previous Board Approved level for the 2005 Test Year. The increase is the result of a $204,084 increase in capital expenditures and an increase of $30,070 in the working capital allowance.

NRG's forecast for capital expenditures is estimated to be $965,207 in 2006 and $867,657 in 2007. NRG is forecasting 44 fewer Rate 2 seasonal customers in 2006 and a further reduction of 27 customers in 2007. This is the result of a recent announcement of a 35% reduction in tobacco quota volumes by the Ontario Flue-Cured Tobacco Growers' Marketing Board[2]. NRG has correspondingly cancelled all capital projects related to Rate 2 customers. This translates to four projects in 2006 and two projects in 2007.

During cross-examination Board staff attempted to determine whether the excess capacity generated from the loss of Rate 2 customers could be used to offset NRG's proposed reinforcement project identified as the Nova Scotia Line. The concern arose from the fact that the benefit/cost ratio of this project is less than one.

The Company indicated that although the loss of Rate 2 volumes may result in some overcapacity, it is not in the appropriate area within NRG's franchise for it to be used for system reinforcement. Although the Nova Scotia Line has a benefit/cost ratio of less than one, NRG indicated that it will not be collecting aid from any customers as it was not possible to identify the customers at this point in time.

With respect to a justification for this project, the Company reiterated its explanation provided in Information Request (IR) No. 6 that the Nova Scotia Line will provide a second feed to the villages of Copenhagen and Port Bruce, as indicated in the colour coded map in Schedule A. In other words, if there was a supply disruption affecting one

[2] The Ontario Flue-Cured Tobacco Growers Marketing Board is a provincial marketing board that operates under the authority of the Farm Products Marketing Act, and the supervision of the Farm Products Marketing Commission. The Board's mandate is the control the production and marketing of all flue-cured tobaccos grown in the province of Ontario. It represents approximately 800 tobacco families plus approximately 150 sharegrowers. For more information, visit www.ontarioflue-cured.com

of the pipelines, the second line could take over providing reinforcement and security of supply. The Company also believes there is a potential to add 48 new residential customers as a result of this expansion with a further possibility of adding one commercial and two industrial customers beyond five years. However, the company indicated that it had not included projections beyond the five-year period in the economic analysis submitted in this application.

Another issue raised by Board staff was related to main additions projects that have been completed to-date in 2006. With less than three months remaining in NRG's 2006 fiscal year-end (September 30, 2006), only $34,358 out of a total of $162,882 has been spent to-date. The Company's testimony indicated that the completion of these projects required 970 man hours. Similarly, main additions for 2007 are estimated to be $232,585 and Board staff's position was that the forecast is overly optimistic. Despite cancellation of some main additions projects, the Company expressed confidence in completing the rest of them. The Company explained that capital expenditures were not added to rate base until the line went into service.

Board staff was also concerned about the substantial rise in the cost of meters for 2006. The Company indicated that a majority of the cost comprised the purchase of a Supervisory Control and Data Acquisition System (SCADA). This system would allow NRG to control the pressure from a central location as opposed to manually adjusting the meters. The balance of the costs was attributed to a new electronic metering system that would allow NRG to read meters remotely. The cost also included a new radio network capable of picking up the electronic signals. The company expected to connect 12 large customers to this new electronic metering system.

Board staff requested the company to clarify why the cost of meters and regulators did not fall in 2006 and 2007 given that a number of main additions projects had been cancelled as indicated in the updated evidence. The company responded in an undertaking that its original estimate for meters and regulators did not include requirements for tobacco loads because it had some meters in its inventory and furthermore it expected that some tobacco customers would terminate service and this would free up meters and regulators that could be re-used.

There was considerable debate on the cost of replacing the company's vehicle fleet. Board staff questioned the justification for replacing a cargo van that is expected to have only 100,000 km on it by the end of fiscal 2007. The targeted replacement cost of all five vehicles during the 2007 test year is $188,000. The Company argued in response that while the mileage on this particular van was relatively low, it was subject to more abuse than other vehicles.

Board Findings

NRG in this application has requested that the Board allow capital expenditures totalling $867,657. These are down from the levels experienced in the previous year. Given the significant reduction in tobacco quotas in the NRG service territory, the Board finds these costs to be reasonable and acceptable.

With respect to the cost of replacing the vehicle fleet, the Board approves the costs with the exception of the one van (2005 Chevrolet Cargo Van). Accordingly, the Board approves a cost of $150,000 ($188,000 - $38,000) for this purpose. The Board does note the subjective nature of NRG's vehicle replacement criteria and the absence of a formal policy in this respect. The Board accordingly directs NRG to develop a written policy for vehicle acquisition, disposition and replacement prior to the next rate case application.

OPERATING REVENUE

NRG's total operating revenue is divided into two components – gas distribution and transportation revenue, and other operating revenue (net.). This latter category is made up of the rental equipment program, contract work program, service work program, merchandise sales, direct purchase fees, delayed payment charges and transfer/connect charges.

NRG's updated evidence indicates that its operating revenue will amount to $4,570,085 in 2007. This is $107,859 more than 2006 forecast and $105,488 more than the previous Board Approved level for the 2005 Test Year. The increase in operating revenue is associated with the forecast of 325 additional customers (net) in 2006 and 367 customers (net) in 2007[3].

Gas distribution and transportation revenue totals $3,889,059 or 85.1% of total revenues. Other operating revenues (net) accounts for the remaining revenue of $681,026. Total customers forecasted for the fiscal 2007 test year is 6,872 with an associated throughput volume of 23,566,141 cubic meters.

NRG's forecast for operating revenue in 2006 and 2007 are lower than the original pre-filed evidence and is attributed to a forecasted loss of Rate 2 tobacco curing customers. NRG is forecasting 44 fewer Rate 2 seasonal customers in 2006 and a further reduction of 27 customers in 2007. This is the result of a recent announcement of a 35% reduction in tobacco quota volumes by the Ontario Flue-Cured Tobacco Growers' Marketing Board.

The original pre-filed evidence did not include volumes related to Imperial Tobacco because NRG forecasted the loss of that customer in fiscal 2007. However, a response to an Information Request[4] revealed that the customer could be in operation until mid to late calendar 2007. NRG's updated evidence indicated a volume forecast of 3,391,247 cubic meters for this customer through to the end of June 2007.

[3] Exhibit C1/Tab1/Schedule 4 Updated Evidence
[4] Board staff IR Number 8

Board staff questioned NRG's residential additions forecast for fiscal 2006 and argued that NRG's prediction of 353 new residential customers in 2006 seemed to be very optimistic.

As of June 2006, NRG added 200 new residential customers. Data from the last ten years for additions by month suggests that NRG may end up adding another 25 to 30 customers by the end of the 2006 fiscal year (September 30, 2006). Board staff added that in order to meet its forecast figure of 353, NRG required the addition of approximately two customers per day till the end of September 2006.

NRG insisted that the forecast was appropriate and with the help of an aggressive advertising and marketing campaign, they were confident that the forecasted figure of 353 new residential customers was realistic. Given that NRG's current penetration rate of 70% on its distribution system is relatively low compared to other utilities, NRG believes there are significant opportunities to grow volumes and customers.

Board staff also questioned NRG's forecast that indicated a loss of 44 Rate 2 customers in 2006 as well as the methodology used to determine that forecast. NRG indicated that it drove by every farm that it had an account with to determine whether they had tobacco in their fields. The resulting number was validated against a 35% reduction in customers corresponding to the 35% reduction in quota. The numbers from the two methodologies were fairly close and the lower number of 77 was used in the application. For 2007, the 2006 number was simply reduced by 35% yielding a total of 50 customers.

With regard to the proposed ethanol plant, Board Staff sought clarification on the impact that the ethanol plant would have on NRG's throughput and distribution system. NRG indicated that its throughput volume would triple due to the significant demand of natural gas the ethanol plant would require. NRG's forecasted load for 2007 is 23.5 million cubic metres and this would increase to 70-80 million cubic metres with the inclusion of the ethanol plant. The existing system in not capable of handling this load for two reasons: (i) the volumes are significantly larger and require a separate feed from the Union Gas system, and (ii) the plant requires a higher delivery pressure than NRG can currently provide.

The panel questioned why NRG was cautious about gaining the ethanol plant as a customer. NRG indicated that the project requires a significant outlay of capital of approximately five million dollars. In addition, the costs that NRG pays to Union Gas under the M9 delivery contract would essentially double as the peak demand would double with the ethanol plant. Moreover, addition of the pipeline would increase NRG's rate base to more than ten million dollars, making NRG ineligible for the capital tax exemption. In addition, property taxes on 31 kilometres of a high-value pipeline would be substantial.

The Board also questioned NRG on how it would be impacted if the tobacco industry disappeared in its entirety in its service territory. NRG indicated that this would lead to $200,000 in costs that would need to be allocated to other rate classes. NRG did not have any contingency plans in place to address this possibility.

In the closing statement, Board staff reiterated their position that the residential customer addition forecast for 2006 and 2007 was too ambitious and this was also reflected in the volume forecast. NRG's reply argument stressed the aggressive advertising and marketing campaign and considered this program crucial to the company's efforts to mitigate the revenue loss from tobacco customers.

Board Findings

The Board accepts NRG's 2007 forecasted total throughput volume and operating revenue of 23,566,141 cubic meters and $4,570,085, respectively.

The Board notes the optimistic forecast with respect to residential customer additions in 2006 and 2007, but accepts NRG's explanation that an aggressive advertising and marketing program will help meet forecasts. The Board also accepts NRG's 2007 forecasted customer numbers of 6,872.

The Board is concerned about the significant reduction in the 2006 tobacco quota and its impact on NRG's tobacco curing customers. NRG has forecasted a further drop of 35% in the tobacco quota resulting in a loss of 27 customers in 2007. The Board acknowledges that the loss of 71 customers in 2006 and 2007 will lead to a significant erosion of this rate class. The Board is also concerned about the lack of data for the 2007 test year with respect to the tobacco quota. Recognising that there is a further risk to this rate class, the Board accepts NRG's forecasted Rate 2 volumes and numbers, but at the same time directs NRG to consider developing a contingency plan to address possible reduction in volumes as well as a potential loss of the entire rate class.

COST OF SERVICE

NRG's cost of service forecast for the 2007 test year totals $3,770,275. Operation and Maintenance costs total $2,149,572 or approximately 57.0% of the total cost of service. Depreciation and amortization totals $731,597 or 19.4% of the cost of service. Property, capital and income taxes account for $440,669 or 11.7% of the cost of service. Gas transportation costs account for the remaining $448,437 or 11.9% of the cost of service.

Net wages and benefits account for approximately 45% of the total Operating and Maintenance costs. A list of some of the important cost items together with a comparison to the 2005 level of costs appears below:

O & M Costs	**2005**[5]	**2007**[6]
Wages	801,900	911,623
Employee Benefits	120,800	132,997
Insurance	265,000	273,911
Advertising	22,000	74,861
Telephone	41,500	33,758
Repair & Maintenance	159,600	149,316
Automotive	54,500	99,551
Regulatory	108,500	193,700

Board staff examined a number of areas including unaccounted for gas, gas transportation costs, automotive expenses, regulatory costs, bad debt expenses, advertising costs and the cost of gas.

NRG has requested modification of the methodology used to account for unaccounted for gas. NRG's methodology uses a 3-2-1 weighting of the unaccounted for gas for the last three years. This is a Board-approved methodology and similar to the one used by Union Gas. The Company is seeking approval to use the same methodology but

[5] Board Approved amounts (RP-2004-0167)
[6] Updated Evidence, Exhibit D1/Tab3/Schedule2/Pg.1

subjecting it to a floor of zero percent. The current methodology does not have a floor limit.

Board staff argued that NRG has reported gas gains in two out of the three previous years, namely 2003 and 2005. NRG argued that a majority of the gas gain is due to NRG's fiscal year end being September when tobacco volumes are at their highest. This can result in significant swings in unbilled volumes as a result of a difference in billing cycle versus the calendar month. NRG also confirmed that it is more of a volumetric issue than an accounting one. NRG indicated that there is no adverse impact on customers. Even if the floor was set at a gas gain of 0.2%, the net impact after tax would be a negligible decrease of $223.

Board staff questioned NRG's proposed automotive expenses of $99,551 which included repair and maintenance costs of $18,735. There was no evidence why repair and maintenance costs were increasing when the company proposed to replace five vehicles in 2007. In response to an undertaking, NRG explained that part of the $18,735 includes expenses related to equipping the new vehicles with accessories such as racks and shelving.

NRG's pre-filed evidence indicated regulatory costs of $192,700 of which $131,700 relate to the 2007 cost of service hearing. In response to a Board staff IR, NRG indicated that it intended to file the next rates case in December 2007. This has since been changed to December 2006. Board staff questioned the rationale for this change considering that NRG submitted a report as per Board's direction in RP-2004-0167 supporting a multi-year rate filing. NRG was of the view that the proposed ethanol plant would result in a significant change in its rate base and operations warranting a cost of service application. However, NRG indicated that it did not wish to wait until the end of the year to file, in effect delaying the current application, for the simple reason that there was some uncertainty around the construction of the ethanol plant.

Board staff questioned NRG on the possibility of a rise in collection and bad debt related costs as a result of an expected loss of Rate 2 customers in 2006 and 2007. NRG indicated that it did not foresee a rise in collection related and bad debt expenses.

Board staff specifically focussed on the proposed advertising expenditures of NRG. The cash rebate program forms a major part of NRG's proposed advertising budget and is estimated to cost $198,250 in 2007. NRG planned to amortise the cost over an eight-year period. The program is intended for residential customers who convert an appliance from an alternative fuel to natural gas. These customers would receive a rebate for the natural gas equipment that they purchased or rented as an incentive to convert to natural gas. For example, a person converting to a natural gas furnace would receive a one-time rebate of $450.

During cross-examination, NRG confirmed that although the ancillary business sold furnaces, water heaters and appliances, none of the advertising expenditures were allocated to the non-regulated portion of the business. NRG argued that the goal of the rebate was to increase throughput and the rebate was distributed irrespective of where the customer purchased the gas fired appliance. However, NRG did agree that majority of the sales or rentals were going through them. Board staff maintained that the ancillary business should bear some of the advertising costs as they derive some benefit from the program. It is fair to assume that fewer people would purchase or rent appliances from NRG without the existence of this program.

The forecast of customer additions was also questioned. NRG forecasted the addition of 353 residential customers in 2006. To-date NRG has added approximately 200 customers and based on historical statistics is likely to add another 25 by the end of the fiscal year. Board staff expressed concern about the numbers and the likelihood of NRG adding another 150 customers by the end of September.

Board staff also questioned the rationale for selecting an eight-year amortization period for the cash rebate program. In reply NRG indicated that the eight year period represented the approximate time to recover the rebate amount in rates from the customer. The net benefit of the program was greater than one beyond eight years.

Another program that NRG planned to introduce was the lead pay program. This is an incentive tool for employees to encourage conversion to natural gas. During cross-examination, NRG explained that the $10 lead fee would be paid only if it resulted in the conversion of an appliance. This program is estimated to cost $6,000 in 2007.

Finally, Board staff examined the gas purchases from NRG Corp., a related company. Board staff was concerned that the contract price in 2006 was substantially higher than the forecasted average price for the year. NRG clarified that the contracted price was determined by calculating the one-year forward strip over the last ten business days of September 2005. Board staff presented an Exhibit “Canadian Natural Gas Focus (October 2005)” that showed the NYMEX 12-month forward price in September. This price was significantly different from the one NRG used in its contract. NRG presented its own evidence, a document titled, “The Source Report” from which NRG determined the price. Board staff expressed satisfaction with the source and the methodology to calculate the price so long as the source and the methodology used were consistent going forward.

In final argument Board staff expressed concern with the forecasted customer additions and the rationale for spending almost ten times the amount for marketing and advertising as compared to past periods. The second issue dealt with the allocation of these advertising expenses. Board staff did not agree with the allocation of 100% of advertising expenses to the regulated side of the business when the ancillary business derives additional sales and profits from this program. Citing the example of the water heater grants program that was allocated 100% to the ancillary business, Board staff questioned if the current program was radically different. Board staff recommended allocating some portion of the proposed advertising and marketing expenses to the ancillary portion of the business.

In its reply argument NRG stressed that all ratepayers across all rate classes would benefit from the marketing campaign as a result of additional throughput. Moreover, there are occasions when the ancillary business does not benefit from the rebate programs. Customers were eligible for rebates even if they purchased their equipment elsewhere. In other words, the ancillary business may not derive all the benefits that Board staff claimed. NRG also confirmed the success of their marketing programs to-date and expressed confidence in meeting their targets.

Board Findings

The Board approves NRG's request for setting the floor of 0.0% for the test year. NRG has recorded gas gains in only 4 of the last 24 years and as tobacco volumes fall, further swings in unbilled volumes are likely to decline.

The Board understands the challenges faced by NRG with respect to serving the ethanol plant and the significant impact this potential customer will have on its cost structure and rates. The Board supports NRG's rationale for filing a cost of service application in December. However, NRG needs to recognize the cost consequences of frequent regulatory filings on its small customer base.

The cash rebate program forms a significant portion of NRG's proposed advertising expenditures. The Board is concerned about NRG meeting its target with respect to customer additions and the overall benefit of this program. However, NRG is confident of meeting this target and the Board accepts this assurance.

It is evident that the cash rebate program will provide some benefit to the ancillary business. The ancillary business is making profits and according to testimony of NRG, the percentage of profit is similar to the regulated portion of the business. The Board directs NRG to allocate a portion of the advertising expenditures for programs that involve selling or renting gas appliances, namely the cash rebate program and the lead pay program, between the ancillary and regulated businesses according to revenues. Accordingly, 85% of program costs will be borne by the regulated business and the balance, 15%, by the ancillary business.

The evidence also discloses an inconsistency between the number of appliances that are likely to be sold or rented under the cash rebate program and the lead fee that will be paid to employees for a successful conversion. The evidence indicates that NRG is likely to convert 201 appliances from other fuel sources to natural gas. In addition to paying a cash rebate for each conversion as discussed previously, the company could also be paying sales people a $10 lead fee for every conversion secured through them. The cost estimate for this expense in the application is $6,000 which would suggest 600 leads. The inconsistency stems from the fact that all customers acquired as a result of leads would be made aware of the cash rebates available and therefore would not be able to exceed the numbers projected for the cash rebate program. Accordingly, it seems appropriate to adjust the cost of the lead pay program from $6,000 to $2,010 based on a maximum of 201 conversions. The Board accepts NRG's rationale for amortizing the costs of the cash rebate program over an eight-year period.

The Board accepts NRG's methodology to calculate natural gas prices associated with purchasing gas from the related company. However, the Board directs NRG to seek prior permission should it decide to change either the source from which prices are calculated or the methodology used to determine the contract price.

CAPITAL STRUCTURE AND COST OF CAPITAL

NRG's proposed capital structure and cost of capital for the 2007 Test Year is detailed below:

Capital Structure – Cost of Capital[7]
2007 Test Year

	Capital Structure ($'s)	Ratios (%)	Cost Rate (%)	Return Component (%)
Long-term debt	6,406,924	66.10%	8.45%	5.58%
Short-Term Debt				
Operating Loan	0	0.00%	6.00%	0.00%
Unfunded Debt	(106,288)	-1.10%	6.00%	-0.07%
Common Equity	3,392,650	35.00%	10.20%	3.57%
Total	9,693,286	100.00%		9.08%

The main differences between the 2005 Test Year Board-approved Capital Structure and Cost of Capital, and NRG's proposal for 2007 are as follows:

- Equity ratio decreases from 50% to 35%
- Return on equity increases from 9.57% to 10.2%
- Long term debt ratio increases from 31.43 to 66.1%
- Long term debt rate increases from 8% to 8.45%
- Short term debt ratio decreases from 17.3% to a 1.1% credit
- Short term debt rate increases from 5.5% to 6%

[7] Exhibit 6, Tab 1, Schedule 1, Updated Evidence

Mr. Bristoll testified as the Company's witness on NRG's proposed capital structure and return on equity. Ms. Kathleen McShane, of Foster Associates Inc., testified as the Company's expert witness. The purpose of Ms. McShane's testimony was to evaluate the reasonableness of NRG's proposed capital structure and to determine the risk premium for the utility. Ms. McShane's analysis and evaluation, Opinion on Capital Structure and Equity Risk Premium for Natural Resource Gas[8] concluded that for the 2007 Test Year, a 35% common equity ratio is reasonable and recommended that a 150 basis point premium be added to the return on equity amount as calculated using the Board's Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities.

During cross examination Board staff explored three issues: (1) the possibility that a range of equity ratios could be appropriate, (2) the factors leading to changes to NRG's equity ratio that the Board considered in previous decisions, and (3) the role risk has in determining capital structure and rate of return.

Ms. McShane agreed that there is a range of acceptable equity ratios. A ratio within the range of 35% to 55% would be reasonable for a specific utility, given the appropriate common equity return for the utility. In the witness's opinion, the Board in previous decisions had approved increases in NRG's deemed equity ratio because the actual ratio had reached 50% and a 50% equity was reasonable for the level of business risk that NRG faced. With regard to the changed circumstances that would prompt a 35% equity ratio, Ms. McShane indicated that the company had re-financed and raised new debt, thereby establishing an actual common equity ratio of approximately 35%; and that 35% is appropriate to use because it is the actual ratio.

Mr Bristoll's rationale for the change was that NRG had been prevented from issuing dividends (due to the Imperial Life Loan covenants) and that, given the low interest rates, the time was right to go to market to re-finance. He indicated that NRG cannot go to market repeatedly and noted that the new structure was good for ratepayers since it reduced NRG's revenue deficiency.

[8] Exhibit E2, Tab 1, Schedule 1

Ms. McShane stated that NRG's risks, and those relative to other gas distributors, had not changed appreciably. The witness confirmed that if there had been a significant increase or decrease in business risk, then that should be reflected in a capital structure or equity return change. With respect to NRG's comparative risk with Enbridge Gas Distribution Inc. (EGDI), the witness concurred with the proposition that if the Board agrees that the business risk of NRG relative to EGDI has declined, then it would lead to a lower risk premium. The witness noted that, if NRG moves to a 35% equity ratio, there is no reason to believe that the overall cost of capital would be any different, assuming no material change in the business risk.

With respect to the proposed 150 basis point risk premium, Ms. McShane indicated that a 150 basis point risk premium was justified. Her conclusions were based on the consideration of three factors: the difference of cost of debt between the utilities, the impact of size on return (Ibbotson Study) and the equity return rate which under a different capital structure would result in an equivalent cost of capital, assuming no change in business risk.

Board staff questioned the witness's assumption that NRG's business and relative risk had not changed since the 1998 Test Year decision in which the Board approved a 50% equity capital structure and a rate of return on equity equivalent to Enbridge Gas Distribution Inc's.

The panel sought clarification regarding the witness's claims that (i) NRG's entire market and not just the agricultural sector, is riskier than Enbridge Gas Distribution Inc.'s, (ii) NRG's residential component is riskier because it is less diversified, more dependent on an agricultural base (iii) NRG doesn't have the diversity of employment that EGDI has, and (iv) the agricultural sector is more risky than industrial markets.

Ms. McShane acknowledged that she had not examined data supporting the conclusion that NRG's residential market is less diversified and also reiterated that her assessment of the market being more risky is based on the total market and not just the residential portion. The witness indicated that she didn't necessarily look at number of customers nor revenue to ascertain relative risk but rather looked at the gross margin attributable to the different customer classes and supported the proposition that the greater the proportion of revenue or gross margin, that comes from residential customers, the less risky the market. The witness did not disagree with the proposition that replacing tobacco load with residential load, and all things being equal, would reduce the overall business risk.

In this regard, the Company filed Exhibit K 2.4[9] which provided comparative customer and market related information for NRG, Union Gas Limited and Enbridge Gas Distribution as set out below.

	NRG	Enbridge	Union[10]
Residential Sector			
Percent of Customers	91	91	90.5
Percent of Volumes	46	37.5	19
Percent of Gross Margin	70	60	59
Commercial Sector			
Percent of Customers	6	8.6	9
Percent of Volumes	14	40	13
Percent of Gross Margin	13	32	26
Industrial Sector			
Percent of Customers	3	0.4	0.5
Percent of Volumes	40	22.5[11]	68[12]
Percent of Gross Margin	17	8	15[13]

Of these three breakdowns by customer class, the gross margin is the most indicative of the utilities' dependence on the industrial class. Note that the Union data are for in-franchise operations only. The industrial gross margin as a percent of the total, inclusive of storage and transportation revenues, is approximately 12%. Note also that the industrial data do not provide any insight into the diversification among industries.

Counsel for IGPC questioned Ms. McShane's reasoning for recommending a 150 basis point premium, despite the fact that in 1995 the Board had approved a 135 basis point premium, when in both cases the equity ratio is 35%, and NRG's risk has declined since that time. Ms. McShane responded that one could not make a direct comparison

[9] EXHIBIT K 2.4:
To Provide Figures for Revenue and Number of Customers for Residential as a Percentage of Total Revenue and Number of Customers for Enbridge Gas Distribution, Union Gas Limited and NRG; To Provide the Percentage of Gross Margin Coming from both Residential and Industrial Customers
[10] Excludes storage and transportation, which accounts for 20% of revenues
[11] Includes wholesale (Gazifere)
[12] Includes large commercial
[13] Includes large commercial

between the two situations and conclude definitively that it represented an increase in risk premium.

Board staff in its closing argument identified two issues for the Board's consideration. The first was whether the equity ratio should be reduced to 35% from its deemed 50%. The second was whether there should be an equity risk premium, and if so, what that premium should be.

Noting Ms. McShane's suggestion that the equity ratio can be between 35% and 55%, Board staff questioned whether deeming an equity ratio at the lower end of the range would impact NRG's ability to raise debt to finance the pipeline for the proposed ethanol plant.

Regarding the 150 basis point risk premium proposed by NRG, Board staff referred to expert witness testimony that small cap companies have greater risk than larger-cap ones and that business risk is related to size and diversity of market. Board staff noted that there is evidence indicating that NRG is similar to Union, on the basis of gross margin by rate class, and that NRG's exposure to the industrial class has declined form 17% to 11%. Board staff suggested that as residential load increases relative to the riskier industrial load, business risk should decline because the margin on residential load is twice that on industrial load.

Board staff also referred to previous decisions which could be of assistance to the Board. In RP-2002-0158[14] Union Gas Limited was granted a 15 basis points premium over EGDI and in EBRO 480[15] NRG was given a 50 basis point premium over Union. Board staff suggested that the appropriate premium for NRG should be around 65 basis points, the sum of 50 and 15.

Counsel for IGPC agreed with Board staff that a risk premium is warranted in the range of 60 to 75 basis points. Mr. Stoll indicated that the recent Bank of Nova Scotia loan and the growth in the number of residential customers suggested a stronger utility for which a

[14] RP-2002-0158, In The Matter of Applications by Union Gas Limited and Enbridge Gas Distribution Inc. For A Review of the Board's Guidelines for Establishing their Respective Return On Equity, Decision and Order, paragraph 45
[15] EBRO 480, NRG Ltd., Decision, Section 6.5.19 and Appendix I, pgs. 5 & 6

150 basis point premium was not warranted. With respect to capital structure, Mr Stoll supported a 35% equity ratio.

NRG addressed two issues in its closing submission: capital structure and return on equity.

The first concerned the new cost of equity calculation proposed by NRG which assumed that NRG's risk had not changed appreciably relative to that of EGDI. Mr King submitted that NRG's relative risk had not changed materially. Although NRG's riskiest customers are forecasted to leave the system, the risk is only reduced if the "leaving" customers are replaced by new customers. Mr King noted that NRG's gross margin from the industrial sector is declining and that, as pointed out by Ms. McShane, Enbridge's and Union's industrial sector is more diversified than NRG's, and consequently less risky.

The second issue raised by NRG was the appropriateness of NRG's proposal to decrease the equity component of its capital structure from 50% to 35%. To the concern raised by IGPC that a low equity ratio will hinder NRG's ability to fund or obtain funding for any capital investments required to attach the new ethanol plant, counsel for NRG pointed to Mr. Bristoll's testimony that the company remains strong, post-refinancing, and that financing particulars would be addressed by the Board when the project plans are firmed-up. On the matter of the dividend pay-out, NRG noted that had it paid a dividend over the past 12 years, it would be in the same position as it is in today in terms of dealing with any funding requirements related to the planned ethanol plant.

Board Findings

NRG in this application requested an equity ratio of 35%. The evidence shows that the actual equity ratio is 41.5%. This is the ratio that results after the Bank of Nova Scotia financing and the payment of $2,038,581 to shareholders.

It is not clear why NRG was proposing 35% equity ratio except that the company's expert witness appeared to believe that was the actual ratio. The Board agrees with the principle that the actual ratio should be used unless the ratio is considered to be unreasonable. In the past, the Board has used a deemed equity ratio for NRG, but that was on the basis that the actual equity ratio was unreasonable. In this case, the Board finds that the actual equity ratio of 42% is reasonable. It does reflect the fact that NRG is a more risky utility than Enbridge Gas Distribution and Union. However, the Board is convinced that the equity financing is a sound third-party financing and there is no basis for assuming that the actual ratio of 42% is unreasonable. Accordingly, the Board sets NRG's common equity ratio to 42% for the 2007 fiscal year.

With respect to the risk premium, NRG requested a 150 basis points equity risk premium over Enbridge Gas Distribution Inc. This Board in the past has allowed Union a 15 basis points risk premium[16] over Enbridge. The Board agrees that risk premiums are appropriate in certain cases. However, the Board does not see why NRG's risk premium should be ten times to what was approved for Union (15 basis points as compared to 150 basis points).

The position of Board staff and IGPC was that there should be some risk premium but that it should be in the range of 60 to 80 basis points.

It is important to note that if anything NRG's risk is declining. The Company's evidence indicates impressive growth figures. These include tripling the number of customers since 1991 and the forecast for 2007 indicates a strong growth in residential load. This is likely to replace in part the risky tobacco load which will reduce the risk that has dominated NRG's business in the past.

It is also significant that the Company has for the first time been able to secure arms length financing for all of its debt. And for the first time NRG has been able to obtain financing from a major financial institution, in this case the Bank of Nova Scotia. The amount of debt is almost twice the level of its previous long-term debt at an interest rate far lower than rates previously paid by NRG. This in itself goes a long way to reducing the risk of NRG as an operating utility.

For the reasons expressed above, the Board is of the view that a risk premium of 50 basis points over Enbridge Gas Distribution Inc. is justified. It should be noted that while

[16] Decision and Order RP-2002-0158, Para 45

the Board has rejected the requested 150 basis points risk premium, it has increased the equity component from 35 to 42 percent which offsets this in part.

FINANCING AND REDEPLOYMENTS COSTS

The Board has asked NRG in previous rate cases to refinance its long-term debt. In RP-2004-0167, the Board indicated that it will address recovery of breakage costs through rates if and when they are incurred. NRG has refinanced its debt and has incurred two types of costs; (1) financing costs with respect to obtaining the new loan from Bank of Nova Scotia and (2) prepayment penalties associated with the retirement of its previous debt instruments.

The financing cost is $47,793 and includes a commitment fee of $20,000, Bank legal fees of $20,000 and another $7,793 in legal fees of NRG. The redeployment costs total $219,116.85 including interest of $5,864.46. The prepayment penalties for the Imperial Life loan and Banco Securities Debenture are $192,970.59 and $20,281.80 respectively. NRG is requesting the recovery of all financing and redeployments costs.

NRG has proposed to recover the financing costs of $47,793 over the term of the new loan, which is over a period of five years, amounting to $9,559 per year. With respect to refinancing costs, NRG proposes to amortize the costs including accumulated interest, over the remaining life of the new loan beginning in the fiscal 2007 test year. The remaining life is forecast to be 53 months as of October 1, 2006.

During cross-examination NRG was asked to explain how the redeployment costs were calculated. The pre-payment penalties on the Imperial Life loan and the Junsen Debenture represents the difference between the July 2009 long-term rate (maturity of the loan) and the rate on the loan net present valued over the remaining period of the loan. This is in contrast to the Bank of Nova Scotia loan which has a three-month interest penalty for pre-payment.

Board staff argued that the Junsen Debenture was held by a related party and in a previous rate case the Board disallowed recovery of the Junsen penalty stating:

> “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."[17]

NRG's reply was that it is not unusual for the lender to have some kind of a pre-payment penalty clause in order to protect their interest and even the Imperial Life loan and the Nova Scotia loan have pre-payment penalties.

Board staff further argued that the Board made those comments within the context of an impending refinancing and the acceptance of a penalty clause in those circumstances was imprudent and not the concept of a penalty clause in general. NRG's testimony indicated that since the financing did not occur at that time, the Board had not disallowed the penalty from being considered in subsequent cases. NRG considered these costs to be prudent and a common practise in lending arrangements.

In reply to an undertaking NRG provided three-month pre-payment penalties for all three loans, Imperial Life, Junsen Debenture and Bank of Nova Socita. The panel asked for this information in order to understand how onerous the Banco Debenture penalty was as compared to Imperial Life and Bank of Nova Scotia. The three-month penalty for Imperial Life works out to $41,446.57, Banco Debenture $6,263.14 and for Bank of Nova Scotia it is $121,867.29. However, NRG did add a caveat that all loans were at different points in time representing different financing needs and different abilities to borrow money.

The second issue that Board staff focused on was the one percent premium on interest rates that the Board approved in 2004 rates. This one percent premium works out to $31,698 inclusive of the impact of income taxes.

Board staff argued that it was evident in the Board Decision RP-2002-0147 that the one percent premium awarded to NRG on its debt was to cover some of the financing and transaction costs related to the refinancing of its debt. NRG's position was that it is not clear what the Board meant and the 9% represented the deemed rate for that year.

[17] RP-2002-0147/EB-2002-0446, Para 84

The last issue in this area dealt with the amortization period that NRG proposed for accounting refinancing costs. Board staff questioned NRG's motive for not charging a portion of the refinancing costs in 2006 when it was evident that lower interest rates on the Bank of Nova Scotia loan will provide some benefit to the company in 2006. NRG quoted the Board's previous decision that states that NRG should come before the Board for recovery of breakage costs in rates. NRG indicated that its application reflects the Board's policy of not implementing retroactive rate increases.

Board staff argued that NRG had benefited in the amount of $40,000 by refinancing at a lower rate of 7.52% as compared to paying a higher interest rate that was attached to their previous loans. Moreover, a portion of the proceeds from the current loan was being paid out as a special dividend to the shareholder and Board staff suggested that the shareholder should be responsible for a part of the breakage fee. NRG did not deny the benefit but did point out that if they wanted they could have refinanced in September or October, a period closer to NRG's fiscal year end. Moreover, the shareholder had not received any dividend since 1994 and if the financing mechanisms had allowed distribution of dividends, the shareholder would have received dividends during the loan period and this could have worked out to be the same as the one-time special dividend.

In closing arguments, Board staff recommended that the Board not allow the recovery of penalty costs associated with the Junsen Debentures, the 1% premium ($31,698) that the Company has already collected in rates in 2004 and an amount of $6,960 representing the interest rate differential between the deemed rate of 8.0% and the actual rate of 7.52% that the company would be paying in the last six months of 2006.

The Junsen Debenture was not an arms-length transaction and the additional penalty clause was entered into after the company was aware that the Board wanted them to refinance. And further there was no evidence whether the company even used the additional credit facility that was the prime motivator to enter into this agreement. Referring to the one percent premium, Board staff reiterated their position that had the Board not intended to give them monies to cover refinancing and transaction costs, they would have given 8% versus the 9% approved in RP-2002-0147. The fact that the refinancing was not undertaken is irrelevant to the fact that over $31,000 had been collected from ratepayers.

In its reply argument, NRG pointed to the Board Decision RP-2004-0167 that instructed the Company to bring forward all refinancing costs when incurred and that is exactly what NRG had done. Penalties related to the Junsen Debenture form part of the refinancing costs. NRG argued that including a breakage fee clause is common practice in lending agreements so as to protect lenders of fixed-rate loans from borrowers disappearing when rates are lowered. Referring to the one-percent premium, NRG reiterated its earlier position that it did not agree with the position of Board staff.

Board Findings

The Board appreciates NRG's efforts to refinance its debt. However, the Board notes that the Banco Securities Debenture was not a third party transaction and the prepayment penalty constitutes a significant portion of the total loan amount (4.28%). However, the Board is aware that most financial agreements do carry a prepayment penalty clause and a 3-month interest penalty is fairly common. The Board therefore approves a 3-month interest penalty for the Banco Securities Debenture. This amounts to $6,263.14 as indicated in Undertaking J1.6.

The Board does not agree with Staff's argument that the one percent premium awarded to NRG in Decision RP-2002-0147 was to recover refinancing and transaction costs. The decision does not explicitly state that the 9% deemed rate on the cost of debt includes a one percent premium to recover future financing costs irrespective of when NRG refinances its debt.

NRG proposes to amortize refinancing costs including interest over a period of 53 months starting October 1, 2006. NRG's intent is to align the amortization period with the term of the loan. The loan is for a period of five years or 60 months beginning in March 2006. NRG has applied for rates effective October 1, 2006. The Board believes that customers should get the same 60-month period and should not be asked to pay more every month in rates because NRG refinanced earlier in 2006. The Board orders NRG to amortise the refinancing costs over a 60-month period and not 53 months as proposed in the evidence.

The Board does not agree with the position of staff that NRG should be allowed to recover the actual cost of 7.52% for the second half of 2006 as opposed to the deemed rate of 8.0% because that would amount to retroactive rate making. A rate of 8.0% was approved in the previous decision and the company is allowed to recover that amount for the entire year.

The following refinancing costs are accordingly approved for recovery:

• Prepayment penalties for the Imperial Life Loan	-	$192,970.59
• Junsen Debenture	-	$ 6,263.14
• Interest costs	-	$ 5,478.93
Total refinancing costs approved	-	$204,712.66

The Board orders that the above costs be amortized over a 60-month period.

The Board approves a rate of 6.00% for short-term debt. This issue was not contested in the proceeding.

COST ALLOCATION

NRG proposed to modify the previously Board approved cost allocation study to reflect the 2007 revenue requirement, to incorporate the updated information and to reflect a number of changes to the functionalization, classification and allocation of costs.

The updates and changes to the cost allocation study fall into three categories. The first category consists of updates to the calculation of the coincident and non-coincident peak allocators and the calculation of the zero intercept study to reflect the most recent information available. The second category consists of changes to the functionalization, classification and allocation factors that are the result of updated information or circumstances. The third category of changes relate to the fully allocated cost study.

NRG did not propose a change to the methodology used in the Fully Allocated Costing Study that was approved in RP-2002-0147.

Board staff focused on the proposed advertising expenditures associated with the cash rebate and lead pay program, specifically in the context of the allocation of the costs of these programs. During cross-examination, NRG confirmed that while majority of the sales and rentals were through its ancillary business, none of the advertising expenditures were allocated to the non-regulated portion of the business.

Board Findings

The Board approves NRG's proposed updates to its previously approved cost allocation model.

With respect to the allocation of costs of the cash rebate program and the lead pay program, the Board notes that based on NRG's testimony the ancillary business is making a profit and the percentage of profit is similar to that of the regulated portion of the business.

The Board notes that since NRG's ancillary business derives some benefit from the sale and rental of natural gas equipment designed to increase the Company's throughput volumes, the Board directs NRG to allocate a portion of the advertising expenditures for programs that involve selling or renting gas applications, between the ancillary and regulated businesses according to revenues.

RATE DESIGN

In order to increase the fixed cost recovery through the monthly fixed charge, NRG proposed to increase the monthly fixed charge from $9.50 per month for Rate 1 customers to $11.50 per month and to decrease the first block delivery charge and increase the second block delivery charge. This proposal will result in an increase of approximately $4 (1%) to a typical residential customer's annual distribution charge. A typical Commercial customer will see no change while a Rate 1 Industrial customer will see an increase of $380 (11%) to the annual distribution charge.

NRG proposed a $2 increase to the monthly fixed charge for Rate 2 customers that would increase the fixed charge from $10.75 to $12.75 per month. In addition, a decrease to the delivery charge in the first block in the April through October period was proposed as was an increase to the delivery charge in the second and third blocks in the April through October period. No changes were proposed to delivery charges in the November through March period. A typical Rate 2 seasonal customer will see an increase of $504 (22%) to their annual distribution charge as a result of the proposed changes.

For the Rate 3 - Large Volume Contract Rate, NRG proposed to increase both the firm demand charge and the monthly fixed charge for these customers, in order to increase the recovery of fixed and demand costs. The monthly fixed charge for Rate 3 customers would increase to $150.00 from the current level of $100.00. The charge for Rate 3 combined customers would increase to $175.00 per month from the current level of $125.00. The firm delivery commodity charge will also be increased in the test year. No changes were proposed to the interruptible delivery commodity charge range in the 2007 test year. Rate 3 Firm customers will see an increase of $4,131 (9%) to their annual distribution charge.

For the Rate 4 – General Service Peaking rate class, NRG proposed to increase the monthly fixed charge by $2.00, from $10.75 to $12.75 per month with a decrease to the first block delivery charge and an increase to the second block delivery charge in the April through December period. The decrease in the first block rate helps to offset the impact of the higher monthly fixed charge. Rate 4 customers will see an increase of $306 (15%) to their annual distribution charge as a result of this change.

For the Rate 5 – Interruptible Peaking Contract Rate, NRG proposed to increase the monthly fixed charge from $100.00 to $150.00 and increase the interruptible delivery commodity charge. There was also a change proposed to the charge related to the minimum annual volume penalty rate. Rate 5 customers will see an increase of $1,096 (9%) to their annual distribution charge.

The table below summarizes the proposed changes to the monthly fixed charge across the different rate classes.

Rate Class	Current Fixed Charge	Proposed Fixed Charge	Difference
1	$9.50	$11.50	$2.00
2	$10.75	$12.75	$2.00
3	$100.00	$150.00	$50.00
Rate 3 Firm	$125.00	$175.00	$50.00
4	$10.75	$12.75	$2.00
5	$100.00	$150.00	$50.00

NRG also proposed a change to the System Gas Fee in Schedule A of its rate handbook, which provides the gas supply charges that are applicable to all system customers served under rates 1, 2, 3, 4 and 5. NRG proposed to increase the system gas fee from $0.001159 per m^3 to $0.001828 per m^3 to cover 100% of the associated allocated costs.

Board Staff sought an explanation from NRG as to what constitutes a “rate shock”, a concept that NRG intends avoiding as outlined in their guiding principles to rates and service terms. NRG could not provide specific criteria of what constituted a rate shock and considered the concept to be subjective. Board Staff specifically questioned NRG with respect to the increase in distribution charges for Rate 2 customers. The Company did agree that the impact on Rate 2 customers was approaching rate shock.

The Company indicated that it had taken steps to mitigate the impact on Rate 2 customers. Elaborating on this measure, the Company stated that the revenue-to-cost ratio of Rate 2 customers is lower than previously Board approved ratios.

Considering the expected decline in number of Rate 2 customers, Board staff questioned the possibility of merging Rate 2 customers with some other rate class. The Company argued that Rate 2 customers pay a much lower rate than some other rate classes and the problem was that they could neither be reclassified as contract customers due to insufficient volumes nor considered for interruptible services.

The Company also stated that the proposal to increase the monthly charge is revenue neutral in each rate class. NRG further added that it will continue to review the level of the fixed monthly charge consistent with the practice of other utilities such as Enbridge and Union.

Considering the impact of a project the size of the ethanol facility, IGPC wondered whether NRG would design a new rate class specifically for them. NRG in its reply confirmed the need for a separate rate.

Board Findings

The Board approves the rate design changes as proposed by the Company and agrees that the alignment of cost incurrence with cost recovery is in keeping with sound rate design principles.

DEFERRAL AND VARIANCE ACCOUNTS

NRG has the following five Board-authorized deferral accounts:

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

Balances in the PGCVA and REDA have been determined in the same manner as in the past. The REDA is projected to have a debit balance of $147.96 at the end of fiscal 2005. NRG proposes that the REDA be continued into the 2007 test year and that it continue to record costs associated with participating in generic hearings and in Union Gas proceedings. The balance in the PGCVA as of September 30, 2005 was a debit of $104,565.91 including a debit of $1,944.76 in accumulated interest. NRG has proposed that the PGCVA be continued into the 2007 test year. The reference price will continue to be adjusted on a quarterly basis through the QRAM process.

The PGTVA reference price of $0.021848/m^3 approved as part of the RP-2004-0167 Decision with Reasons dated December 20, 2004 for fiscal 2005 rates remains in effect for fiscal 2006. NRG has proposed to dispose of the balances in this account on completion of fiscal 2006. As part of this proceeding, NRG has proposed to change the reference price used when calculating the balance recorded in the PGTVA to $0.019029/m^3 for fiscal 2007. This is the projected rate that is required to recover the forecast gas transportation costs payable to Union.

The GPRA is used to record increases or decreases in the value of gas inventory available for sale to sales service customers due to changes in NRG's PGCVA reference price. The monthly inventory balances used in calculation of the GPRA are based on a deemed level of unaccounted for gas (UFG) of the total throughput volume. NRG has proposed that the GPRA be continued in the 2007 test year, based on a deemed UFG of 0.0%.

The GCDRA was approved by the Board in the RP-2004-0167 Decision with Reasons dated December 20, 2004. It was established to track the variance between the amount collected from ratepayers ($531,794), as authorized by the Board in RP-2004-0167/EB-2004-0413, and $177,265 in each of three years. As part of this application, NRG has proposed that the GCDRA be continued for the 2007 test year. This will be the third and final year for the GCDRA. NRG has requested that the rate of $0.008230/m^3 be continued.

At the start of the hearing, NRG sought an approval from the Board to set up a Refinancing Cost Deferral Account (RCDA) to track breakage and penalty costs that it has incurred to refinance its debt. The updated evidence of NRG indicated a debit balance of $219,116.85 including a debit of $5864.46 in interest at the end of fiscal 2006. NRG has proposed to recover the balance related to the refinancing account by amortizing the costs, including interest, over the remaining life of the new loan beginning in the fiscal 2007 test year.

NRG has proposed to change the methodology used to calculate interest rates for deferral and variance accounts. It has proposed to use the Bank of Nova Scotia prime interest rate in effect at the time of each QRAM filing as the basis for the interest rate to be used in the subsequent quarter.

Board Findings

The Board approves changes to the reference price in the Purchased Gas Transportation Variance Account (PGTVA), from $0.021848/m^3 to $0.019029/m^3 for fiscal 2007.

The Board approves NRG's request to continue the Gas Purchase Rebalancing Account (GPRA) in the 2007 test year, based on a deemed unaccounted for gas of 0.0%.

The Board approves the setting up of the Refinancing Cost Deferral Account (RCDA) to track breakage fees and other related costs. However, the balance in the account will be as stated in this decision. NRG will include a total amount of $204,712.66 in this account, including $5,478.93 in accumulated interest at the end of fiscal 2006. NRG will recover this amount by amortizing it over a period of 60 months beginning in the fiscal 2007 test year.

The Board does not accept NRG's proposal to change the methodology to calculate interest rates for deferral and variance accounts. This is part of a separate generic proceeding (EB-2006-0117) and will be tabled before the Ontario Energy Board Rates Committee in October 2006. The Decision by the Rates Committee will determine the appropriate interest rates for use in variance and deferral accounts.

SUMMARY AND RATE ORDER

NRG claims a delivery-related revenue deficiency of $135,879 for fiscal 2007. This revenue deficiency/sufficiency is adjusted to reflect the following Board findings in this decision.

- Lower advertising expenses of $8,008 in fiscal 2007
- Reduction of replacement cost of one van ($38,000)
- Reduction of common equity ratio from 50% deemed to 42%
- An equity risk premium of 50 basis points over Enbridge Gas Distribution Inc.
- Reduction of $14,404.19 in refinancing costs including interest
- Amortization of refinancing costs over a 60-month period as compared to 53 months as proposed in the application

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

- Financial schedules for the test year reflecting the Board's findings in this decision, i.e. Rate Base, Operation Revenue, Cost of Service, Capitalization/Cost of Capital, Determination of Revenue Sufficiency/Deficiency.
- Rate schedules for 2007 flowing from the above calculations and other Board findings in this decision.
- A list of deferral/variance accounts approved for the 2007 fiscal year.
- Notices to customers to accompany the first bills reflecting the new rates and bill adjustments.

DATED at Toronto, September 20, 2006

ORIGINAL SIGNED ON
BEHALF OF THE PANEL BY

Gordon Kaiser
Presiding Member and Vice Chair

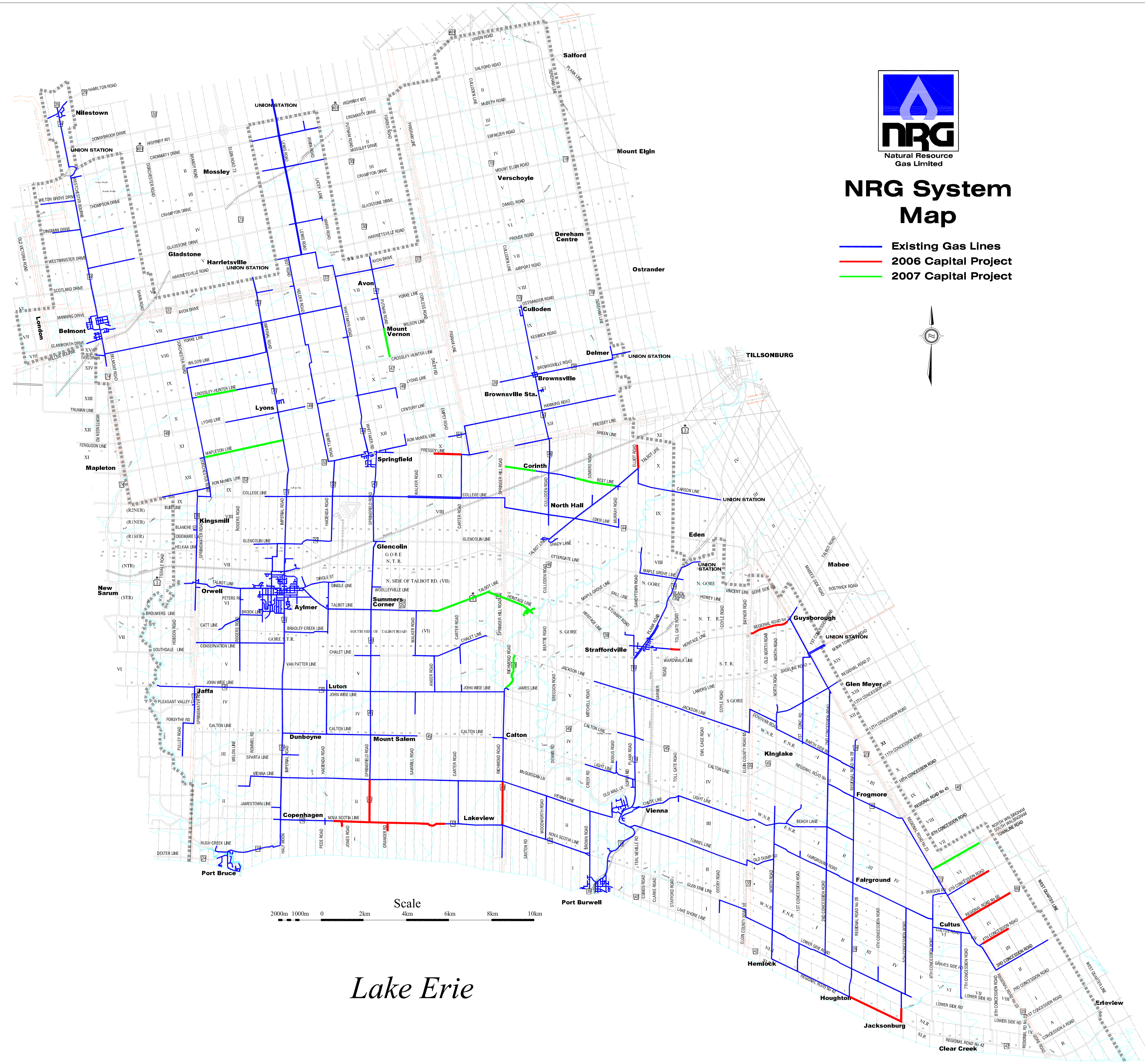
SCHEDULE A TO

DECISION AND ORDER

BOARD FILE NO. EB-2005-0544

NRG SYSTEM MAP

DATED SEPTEMBER 20, 2006



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SCHEDULE B TO

DECISION AND ORDER

BOARD FILE NO. EB-2005-0544

CHART: CHANGES TO APPROVALS REQUESTED

DATED SEPTEMBER 20, 2006

Schedule B

CHANGES TO APPROVALS REQUESTED

	Request	Approval	Reference
CAPITAL EXPENDITURES			
Automotive	Replacement of 5 vehicles at a cost of $188,000	Replacement of 4 vehicles at a cost of $150,000	p.9
COST OF SERVICE			
Cash Rebate and Lead Pay Programs	100% to regulated business	85% to regulated, 15% to ancillary	p.18
Advertising Expenses[1]	$74,861.00	$66,853.00	p. 18 & 19
CAPITAL STRUCTURE & COST OF CAPITAL			
Debt to Equity Ratio	65-35	58-42	p.26
Equity Risk Premium	150 bps	50 bps	p.26
FINANCING & REDEPLOYMENT COSTS			
Junsen Debenture	$20,281.80	$6,263.14	p.32
Interest Cost	$5,864.46	$5,478.93	p.32
Amortization of refinancing costs	53 months	60 months	p.32
COST ALLOCATION			
Marketing Programs	100% to regulated	If involves selling natural gas equipment – proportion according to revenue between ancillary and regulated	p.34

[1] Reflects reduction of $4,291 to the lead pay program and $3,717 to the cash rebate program.