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Toronto, September 24, 2010

Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700
2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Walli:

RE: Natural Resource Gas Limited
Distribution Rates (Fiscal 2011) (EB-2010-0018)
Argument-In-Chief

On behalf of NRG, please find enclosed its Argument-in-Chief in the above-noted matter.

Yours very truly,

Richard King

RK/mnm
Enclosure

cc. Jack Howley (NRG)
Laurie O'Meara (Ayerswood)
Kathi Litt (ERA)
Heather Adams (Town of Aylmer)
Phil Tunley (Counsel to Town of Aylmer)
Paula Zarnett (IGPC)
Scott Stoll (Counsel to IGPC)
Patrick McMahon (Union Gas Limited)
James Wightman (VECC)
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Michael Millar (Ontario Energy Board)

EB-2010-0018

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Natural Resource Gas Limited to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, transmission and distribution of gas as of October 1, 2010.

NATURAL RESOURCE GAS LIMITED
ARGUMENT-IN-CHIEF

September 24, 2010

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A. INTRODUCTION

1. This Argument-in-Chief sets out the argument of Natural Resource Gas Limited ("NRG") in respect of the seven outstanding matters in NRG's application for fiscal 2011 gas distribution rates.

2. These seven issues are:

   (1) Capital Cost of the IGPC Pipeline

   (2) IGPC Period Costs

   (3) Deferral and Variance Accounts

   (4) Appropriate Amortization Period for Regulatory Costs

   (5) NRG Gas Costs from a Related Party

   (6) Cost of Capital and Rate of Return

   (7) Cost Allocation

3. There may be other issues raised by Board Staff and intervenors outside of these seven main issues. Further, given that no other party filed any evidence, NRG cannot anticipate all arguments to be made by intervenors. Consequently, there will be some issues that NRG will only be able to address in its reply argument.

4. In addition, this Argument-in-Chief does <u>not</u> address the non-rate related matters contained in the motion materials filed with the Board by Integrated Grain Processors Co-operative Inc. and IGPC Ethanol Inc. ("IGPC") on August 3, 2010. Thus, this Argument-in-Chief does <u>not</u> address the following issues: (a) the jurisdiction of the Board to adjudicate the Pipeline Cost Recovery Agreement ("PCRA") and Gas Delivery Agreement ("GDA") entered into between NRG and IGPC; (b) the appropriate capital cost or aid-to-construct for the IGPC Pipeline pursuant to the terms of the PCRA; (c) the amount of financial assurance IGPC is obliged to pay for delivery of gas under the GDA;

(d) the determination of cost awards in connection with a June 2007 motion and a February 2008 motion related to the IGPC Pipeline (EB-2006-0243); (e) the ability of IGPC to recover costs related to gas nominations by NRG in July 2008; or (f) the costs of IGPC's motion of August 3, 2010.

5. In addition, this Argument-in-Chief does <u>not</u> address the five-year Incentive Regulation Mechanism ("IR Plan") proposed by NRG in its application, as all parties have agreed to deal with this issue in Phase 2 of this proceeding (once fiscal 2011 rates are established).

B. CAPITAL COST OF THE IGPC PIPELINE

(a) Overview

6. The original capital cost estimate for the IGPC Pipeline was $9,100,000. This estimate was prepared by Aecon Engineering, a company with extensive pipeline construction expertise, and the estimate was before this Board at the time that it granted leave to construct the IGPC Pipeline.

7. NRG ultimately built the IGPC Pipeline on time and under budget. NRG is seeking to include $8,626,353 in its rate base as the capital cost of the pipeline. IGPC argues that the appropriate amount for inclusion in rate base is approximately $7.5 million.

8. The nearly $1.1 million in costs that IGPC does not agree with are made up primarily of the following (based on IGPC's Undertaking J2.2):

- $140,000 administrative penalty levied against NRG in June 2007;
- $362,782 in legal costs;
- $349,609 in project management fees (Mark Bristoll);
- $140,000 in interest costs; and,
- $81,041 classified as "miscellaneous".

(b) <u>Administrative Penalty</u>

9. NRG included the administrative penalty of $140,000 in the capital cost of the IGPC Pipeline because it was a cost incurred in connection with the construction of the IGPC Pipeline.

10. NRG believes that this cost (if it materializes) is appropriately IGPC's, since the need for the motion that gave rise to the proceeding was unnecessary. The rationale for the emergency motion was that if NRG failed to sign two contracts by the end of day on June 29, 2007, then the financing of the IGPC ethanol plant would fall apart and there would be no project. As Mr. Grey admitted under cross-examination, NRG indeed did not sign the contracts until a week after June 29, 2007, yet the financing for the IGPC ethanol plant did not fall apart and of course, the plant has been constructed and is in operation.

11. NRG did not sign the contracts because it wanted additional time to ensure its obligations under those contracts did not put NRG's shareholder or ratepayers at unnecessary risk. As a public utility, NRG has to be mindful of any contractual obligations with significant cost consequences, since these costs often get placed on the backs of ratepayers. So despite the Board's threat at the June 29, 2007 motion to levy a penalty, NRG felt the prudent thing to do was to take the additional few days to get comfortable with the contracts before signing. NRG had a choice on June 29: (a) take this additional time to understand the obligations placed upon the company (and potentially its customers); or (b) sign the agreements without taking the time, in order to satisfy third party financial arrangements of a potential customer. NRG did what it thought was prudent.

12. Notwithstanding the above, the Board Panel in this case has stated that it is looking into the penalty and indicated that it is an amount that may come away from the amount in dispute. NRG is in the Board's hands on this issue, but until such time as the Board's finding and the penalty itself is expunged, NRG submits that this amount is properly included in the capital cost of the pipeline.

(c) <u>Legal Costs and Project Management Generally</u>

13. Because the IGPC Pipeline was a dedicated line for one customer, completing the IGPC Pipeline was not a matter of NRG dealing with a contractor in bilateral negotiations. Instead, IGPC and its legal counsel participated in virtually every task involved to bring the IGPC Pipeline into commercial operation. As noted by IGPC itself, it essentially contracted (in the PCRA) for a greater role in all aspects of the development and construction of the IGPC Pipeline.

14. As set out in Mr. Cowan's affidavit, NRG does not dispute IGPC's interest in being intimately involved with the project (given that the project was solely for the benefit of IGPC, and IGPC would ultimately bear the costs). This presumably made good business sense for IGPC.

15. However, one consequence of this involvement in the project was that it greatly added to the administrative burden involved in completing the IGPC Pipeline. This dynamic meant that more meetings, discussions, emails, etc. were involved in the entire process. This, of course, increased consulting and legal costs.

16. Notwithstanding this, it appears that the majority of the costs being contested by IGPC are precisely those costs caused by IGPC's participation in the development of the IGPC Pipeline. IGPC got what they contracted for, but don't want to pay for it.

17. The record in this proceeding contains complete copies of lawyers invoices over many months/years, and every docket entry made by Mr. Bristoll. From the end of 2006 to mid-2008, NRG's then-President (Mr. Mark Bristoll) spent most of his time (and during certain periods, all of his time) working on the IGPC Pipeline.

18. The record in this proceeding contains examples of the intimate involvement of IGPC's legal counsel in matters such as procurement of pipeline.

19. The record in this proceeding notes that Mr. Bristoll, who is a Chartered Accountant with expertise in the construction industry, was able to rely upon some of the construction executives in NRG's related companies. These executives gave many hours of their time for free.

20. The record in this proceeding notes that weekly status calls among NRG, IGPC, the contractor and even the Town of Aylmer commenced prior to NRG even obtaining leave-to-construct from the Board.

21. NRG agrees with IGPC that the proportion of legal and project management fees expended by NRG to carry out this project were greater than the typical capital project carried out by NRG over the decades that it has been in business. But all of these costs were driven by IGPC's desire to be intimately involved in the project.

22. Notwithstanding these administrative burdens, NRG built the IGPC Pipeline within the time and budgetary estimates given in the leave-to-construct proceeding.

(d) Reasonability of Legal Costs and Project Management Fees

23. In order to demonstrate that the legal costs and costs for Mr. Bristoll's time are reasonable, NRG prepared the following:

- In Undertaking JT 1.16, NRG demonstrated the reasonableness of Mr. Bristoll's rate by benchmarking it to the rate charged by a Chartered Accountant of Mr. Bristoll's seniority.

- NRG retained the services of the accounting firm of Neal Pallett to carry out an audit of Mr. Bristoll's emails sent in relation to the IGPC Pipeline. The audit period covered December 2007 to October 2008. The audit results show that Mr. Bristoll sent and received a total of 1,959 emails related to the IGPC Pipeline during that 11 month period.

- NRG asked MIG Engineering to comment on the typical level of consulting, legal and administrative time for analogous pipeline projects.

24. With respect to the reasonableness of Mr. Bristoll's rate, Board Staff and intervenors may take the view that because Mr. Bristoll was NRG's President, NRG should only be able to re-coup a portion of Mr. Bristoll's salary, or an administrative fee based on a percentage of the costs of the IGPC Pipeline. It is NRG's position that that would not be appropriate. Mr. Bristoll was, for significant stretches of time, dedicated nearly 100% to

the IGPC Pipeline. Further, as mentioned above, Mr. Bristoll was a Chartered Accountant with a number of years of experience in the construction industry who also drew upon many hours of unbilled time spent on the IGPC Pipeline project by senior construction executives in NRG's related companies. These are some of the most experienced construction executives in southwestern Ontario. NRG believes that Mr. Bristoll's accounting and construction expertise (and his ability to draw on senior officials in NRG's related construction companies) is a key reason why the IGPC Pipeline was built on time and significantly under budget.

25. With respect to the Neal Pallett audit of the <u>quantum of Mr. Bristoll's time</u> claimed, the analysis shows that even during the period of time between December 2, 2007 and October 24, 2008, Mr. Bristoll sent and received a total of 1,959 emails in relation to the IGPC Pipeline project, broken down as follows:

IGPC Contract Negotiations	323 emails
Construction Contract	372 emails
Financing for IGPC Pipeline	182 emails
Engineering Matters	289 emails
Commissioning / Testing	73 emails
Material Acquisition	31 emails
Letter of Credit	161 emails
Transfer Station Testing	365 emails
June 2008 Motion	15 emails
Miscellaneous (Assignments/consents)	148 emails

26. Neal Pallett's analysis was that, based on the hours billed by Mr. Bristoll, this amounted to 27 minutes (on average) per email. NRG believes that this is indicative of the fact that the amount of time being claimed for Mr. Bristoll is reasonable (given Neal Pallett's conclusion that some emails would take only a nominal amount of time, but others would take several hours).

27. The only anomaly noted in the detailed audit was a duplication of time on December 18, 2006. NRG has previously agreed to a reduction of $3,540 to Mark Bristoll's time.

28. With respect to the MIG Engineering letter prepared at NRG's request for the benefit of IGPC and the Board, the purpose of the letter is to provide (in broad terms) the typical level of "soft" costs associated with a major pipeline construction project.

29. Based on MIG's letter, the "soft costs" of a major pipeline project (comprised of engineering design, procurement, contract administration, inspection and as built/documentation) is typically 17.5% of the total construction costs of a project. Note that this does not include defining project scope, regulatory applications, and customer negotiations/resolutions, which would be provided on a "Time and Material" basis and could attract an administration charge of 10% for any third party assistance.

30. Based on MIG figures, NRG's costs are in-line with those noted as typical by MIG. Given the extensive involvement of IGPC and its counsel in every detailed aspect of the IGPC Pipeline process, which compounded the "soft costs" of the project, one would have expected them to be higher.

(e) <u>Interest</u>

31. IGPC has stated that the appropriate interest charges to be included in rates is $48,615, and not the $190,605 applied for by NRG.

32. During cross-examination, NRG agreed to re-examine and if necessary re-calculate the interest on the grounds that the timing of the interest period calculation commenced at an inappropriate point (i.e., at the original date as opposed to the date that IGPC received the invoices). NRG agreed with IGPC that that approach was correct, and carried out such recalculation in Undertaking J1.5. On that basis, the interest calculation comes to $113,271, which is comprised of:

- "Aid to Construct" Interest: Interest is calculated from the due date of the Aid-to-Construct invoice to the date the amount was received from IGPC. The rate applied here is Prime plus 1% in accordance with the PCRA (section 3.8).

- "Project Interest During Construction": Interest is calculated from the date the last Aid-to-Construct payment was due to the date the final invoice from the primary contractor was received. During this period, NRG was financing the construction costs. The rate applied here is Prime plus 2% in accordance with the

PCRA (section 3.14(d) – a "reasonable cost of interest during construction"). NRG's position is that this represents a reasonable interest cost.

33. NRG understands that the Board is not bound by the PCRA when determining the any amounts to be included in rates. However, NRG believes that the $113,271 represents a reasonable amount of interest to be charged.

(f) Miscellaneous

34. IGPC contests three separate amounts under the heading "miscellaneous": (a) $9,360 in costs from Ayerswood; (b) $9,681 for Neal Pallett costs; and (c) $62,000 in insurance costs.

35. The Ayerswood amount relates to time spent by John Camara (an Ayerswood construction manager) to assist Mr. Bristoll with some of the research and work related to obtaining bids and managing the contractors and consultants.

36. The Neal Pallett costs relate to the company obtaining tax advice on structuring the PCRA and GDA and financing, dealing with capital tax questions in order to determine IGPC expenses, etc. All of these issues related to the IGPC pipeline and were for the benefit of NRG and its ratepayers (not its shareholder). Finally, the amount claimed here is $7,369 (and not $9,681) as indicated in Mr. Cowan's affidavit.

37. The $62,000 insurance figure represents an allocation of NRG's insurance during the development and construction of the IGPC Pipeline.

C. IGPC PERIOD COSTS

(a) Overview

38. In addition to disputing the capital cost of the pipeline, IGPC is also disputing some of the operating, maintenance and administration costs that NRG is proposing to include in its revenue requirement, which would be directly allocated to IGPC.

39. Again, because there is no evidence from IGPC on this point, NRG will have to wait for IGPC's argument in order to fully respond. However, based on cross-examination, it appears as though IGPC may contest certain proposed maintenance and insurance costs related to the IGPC Pipeline.

(b) <u>Maintenance Costs for the IGPC Pipeline</u>

40. NRG is proposing to contract the maintenance services for the IGPC Pipeline to a third party (MIG Engineering, the company that built the IGPC Pipeline).

41. While NRG has significant internal experience in the operation and maintenance of natural gas pipelines, NRG does not have experience with high pressure steel pipeline such as the dedicated line serving IGPC. Consequently, in order to ensure that the IGPC Pipeline was properly maintained, NRG thought it prudent to have this work carried out by a qualified third party. NRG looked to MIG Engineering to put together a maintenance program, for a number of reasons: (a) because of MIG Engineering's knowledge about the IGPC Pipeline; (b) because MIG Engineering had carried out the construction of the IGPC Pipeline on time and within budget, which gave NRG confidence in terms of MIG's pricing and professional responsibility; and (c) MIG is located reasonably close to NRG's service area. For these reasons, NRG did not believe that a competitive RFP to provide maintenance services for the IGPC Pipeline was warranted.

42. NRG believes that the maintenance costs outlined in the MIG Engineering proposal are reasonable for a number of reasons:

- Although NRG does not have expertise with high pressure steel pipeline, NRG does have a wealth of experience in gas pipeline maintenance. NRG personnel reviewed the proposal with MIG Engineering and believe the services outlined to be commensurate with good utility practice, and the costs to be reasonable.

- NRG does not believe the cost of the MIG Engineering maintenance proposal to be extraordinary in relation to the capital cost of the IGPC Pipeline ($8.6 million).

Annual costs are approximately $112,000 (other costs are one-time or once every several years).

- IGPC has not provided any better evidence to demonstrate that the MIG Engineering proposal is unreasonable (in whole or in part). In fact, the MIG letter filed as part of Undertaking J1.14 sets out the regulatory requirements underpinning the maintenance work, and notes that the purpose of the activities are to ensure the safety of the public, customers and owner as well as the integrity of the pipeline.

- NRG's only motivation for incurring these maintenance costs is safety and reliability. NRG makes no money off of this contract.

(c) Insurance Costs

43. NRG is unsure to what extent the quantum of NRG's insurance will be contested by IGPC. NRG is aware that IGPC will contest the cost allocation of insurance expenses, and deal with this issue later under the Cost Allocation portion of this Argument-in-Chief.

44. With the addition of the IGPC Pipeline, NRG thought it prudent to increase its Umbrella Liability insurance coverage, as well as to obtain insurance: (a) for the new IGPC transfer station; and (b) to cover a business interruption event that would result in no revenues being received from IGPC.

D. DEFERRAL AND VARIANCE ACCOUNTS

(a) Background

45. NRG's evidence in respect of its deferral and variance accounts is found at Exhibit D1, Tab 7, Schedule 1.

46. NRG has four existing deferral/variance accounts: (a) a Purchased Gas Commodity Variance Account ("PGCVA"); (b) a Purchased Gas Transportation Variance Account

("PGTVA"); (c) a Gas Purchase Rebalancing Account ("GPRA"); and (d) a Regulatory Expense Deferral Account ("REDA"). NRG is requesting that these four accounts be continued. No party to the proceeding has objected to the continuance of these accounts.

(b) New IFRS Deferral Account

47. NRG is also requesting an order of the Board authorizing NRG to establish a deferral account to record the costs incurred to assess conversion to the IFRS accounting standard. Ultimately, it was determined that NRG will not have to convert. Costs to date have been minimal. Nevertheless, NRG submits that these costs are eligible for inclusion in a deferral account because: (a) they are not included in the costs proposed to be recovered through distribution rates; (b) the need to incur these costs is beyond management's control; and (c) the costs are expected to be immaterial.

(c) PGTVA Reference Price

48. With respect to the PGTVA, NRG is requesting that the Board reset the PGTVA reference price for fiscal 2011, and replace the single reference price with two reference prices, as follows:

- $0.023909 per cubic metre for Rate Classes 1 through 5
- $0.0105000 per cubic metre for Rate Class 6

49. NRG makes this request in order to clear the credit balance in the PGTVA (i.e., bring the PGTVA balance to zero) by the end of the fiscal 2011 year.

(d) Updated REDA Account Balance

50. On August 18, 2010, NRG filed amendments to the amounts in its REDA account based on discussions in the Technical Conference and Settlement Conference. These amendments involved revisions to Exhibit D1, Tab 7, Schedule 1, and a new Exhibit D1, Tab 7, Schedule 2.

51. NRG proposes to dispose of a REDA balance of $173,907, which is comprised of costs incurred in connection with: (a) EB-2006-0209 (Multi-Year Incentive Rate Regulation

for Gas LDCs); (b) EB-2007-0606/0615 (Commodity Risk Management); (c) EB-2008-0106 (Cessation of Service); and (d) EB-2008-0273 (Long-Term Gas Supply and Upstream Transportation).

52. All of these, with the exception of EB-2008-0106, were generic proceedings (i.e., applicable to all gas distributors).

53. EB-2008-0273 was a proceeding initiated by Union Gas Limited to discontinue service to NRG (or in the alternative, obtain financial assurance from NRG or have NRG switch its contract start date with Union) on the basis that changes to accounting rules in 2006 required NRG's retractable shares to be reported as a liability and not equity in NRG's financial statements.

54. Union's demands would have had an adverse impact on NRG's shareholder and NRG's ratepayers, so NRG declined to accede to Union's request.

55. Further, NRG felt that Union's application was entirely without merit, because:

- the retractable feature of NRG's common shares had been in existence long before 2006;
- Union acknowledged during the proceeding that NRG had never been late or missed a payment to Union; and,
- Union's application was purportedly based on alleged concerns about NRG's financial viability, but NRG's financial condition had not changed – the only thing that had changed was an accounting rule.

56. Notwithstanding this, the Board criticized NRG, stating that NRG had "stone-walled" Union because NRG failed to engage in discussions with Union to provide financial assurance. With respect, this makes no sense. What customer (in any context), would agree to engage in discussions with a supplier that they had paid on time for decades, particularly when the customer's financial condition had only improved over the course of the customer-supplier relationship? As noted earlier, NRG was protecting its

shareholder and ratepayers from an unreasonable request. It should not be punished for doing so.

57. Further, the unreasonableness of the request was recognized by the Board in its Decision. The Board did not order the discontinuance of service (Union had withdrawn this requested relief). The Board also denied Union's request for financial assurance from NRG. Finally, the Board also denied Union's request to move the start date of NRG's long-standing contract with Union.

58. The only thing that the Board ordered was that NRG postpone the retraction of the shares in favour of Union. This relief, quite frankly, served no purpose. The shares had already been postponed to NRG's lender (i.e., the retractable nature of the shares had already been *de facto* removed). NRG had pointed this out to the Board Panel in EB-2008-0106, but advised the Panel that NRG would be pleased to postpone the shares' retractability in favour of Union if the Board thought that would be of assistance to the Board and Union. When the Board Panel during the hearing asked Union directly if this would satisfy their concern, counsel for Union said that a postponement would <u>not</u> satisfy Union. In the end, that was all that Union got.

59. During the oral phase of the hearing, the last sentence of the Board's Decision and Order was put to NRG's witness panel. The last sentence states that: "The Board also directs that costs being paid by NRG shall be paid by NRG's shareholder and not passed on to NRG rate payers." This sentence comes after a discussion of costs incurred by the intervenors. NRG's shareholder did pay the costs of intervenors.

60. It is NRG's position that the word "costs" in the last sentence of the EB-2008-0106 Decision does not extend to NRG's costs incurred, and that these costs should be treated as normal regulatory costs.

61. In normal civil litigation, if a party declines a settlement offer and the court-ordered outcome does not exceed that settlement offer, or is exactly what the offer proposed, the party that declined the offer will bear all of the costs of the proceeding from the date the offer was made. The rationale for this long-standing rule is straightforward – it

encourages parties to treat reasonable settlement offers seriously and avoid frivolous proceedings and wasting court time.

62. While the Board has discretion with respect to its order-making, NRG has no specialized expertise in the field of cost awards. NRG sees no reason why the general rule applicable to costs was not followed in this case (i.e., why Union was not required to pay costs). Having been ordered to pay intervenor costs in contravention of this rule, NRG submits that to interpret this last sentence of the EB-2008-0106 proceeding as requiring NRG's shareholder to bear NRG's costs of the proceeding would only compound an incorrect and unsupportable decision.

(e) Proposed Disposition of the PGTVA and REDA Account Balances

63. NRG proposes to dispose of the net balance recorded in the REDA and in the PGTVA as of September 30, 2009 through a rate rider that will operate for the 2011 Test Year. These costs were prudently incurred (because they were mandatory generic proceedings, or proceedings that ultimately benefited the utility and its ratepayers), were beyond NRG's control and were not previously recovered through rates.

64. NRG previously sought a Board Order authorizing the disposition of these amounts through rates (Board docket EB-2009-0020). The Board did not grant that application. This is the first opportunity since that Decision was issued to seek disposition. NRG acknowledges that its proposed disposition of the balances recorded in these accounts as of September 30, 2009 during the 2011 rate year can be expected to overlap with the disposition through rates of the balances recorded as of September 30, 2010. NRG notes that the net balance to be disposed of is likely not material in context of NRG's customer base – approximately 7,000. NRG also notes that further delay in disposing of these balances through rates will result in further carrying costs and risks in recovering the balances from customers who did not cause the costs to be incurred.

65. NRG proposes to assign responsibility for the PGTVA balance by assigning IGPC its appropriate share of the balance, and developing a fixed charge rate rider. NRG proposes to assign responsibility to all other customers as follows:

- Responsibility for the remaining PGTVA balance will be assigned based on volumetric deliveries in the 2010 Bridge Year.
- Responsibility for the REDA account balance will be assigned equally to each customer.
- The net amount will be recovered from each customer equally over the 12 months of the 2011 Test Year (or as soon as possible after a Decision is rendered in this case) through a fixed charge rate rider.

66. This approach is not expected to result in rate shock to NRG's customers.

E. <u>APPROPRIATE AMORTIZATION PERIOD FOR REGULATORY COSTS</u>

(a) <u>Overview of the Issue</u>

67. The parties to this proceeding have settled the quantum of NRG's regulatory costs to be included in NRG's fiscal 2011 revenue requirement, but one contingent issue remains unsettled – namely, the appropriate amortization period for the regulatory costs in the event that the Board does not approve a five-year IR Plan.

68. The parties to the Settlement Agreement agreed to NRG's recovery of $450,000 of regulatory costs in rates, amortized over a five-year period (to reflect the five-year IR Plan proposed by NRG).

69. As noted in the Settlement Agreement, in the event that the Board does not approve a five-year IR Plan, the parties disagree as to the appropriate amortization period for these regulatory costs. Consequently, as set out in Issue 4.4 of the Settlement Agreement, the parties agreed to have the Board determine the appropriate amortization period.

70. This issue is made slightly more complicated by the fact that the Board will have to establish base rates for the fiscal 2011 test year without having completed Phase 2 of this proceeding (which will deal solely with the IR Plan, including its term).

(b) <u>NRG's Position on the Appropriate Amortization Period</u>

71. In the event that the Board approves an IR Plan that is three years or less in duration, NRG proposes that the regulatory costs agreed to by the parties be amortized over three years. Obviously, "three years or less" would encompass a rejection of an IR Plan (i.e., no IR Plan is approved and the outcome of this proceeding inclusive of Phase 2 is simply distribution rates for fiscal 2011).

72. In the event that the Board approves an IR Plan that is four or five years in duration, NRGs position is that the regulatory costs should be amortized over the approved term of the IR Plan.

73. NRG expects that intervenors will only take issue with NRG's position in respect of the first scenario (i.e, where the IR Plan approved is three years or less in duration). Intervenors may argue that to spread significant regulatory costs over only three years is an expensive proposition for a relatively small customer base. NRG's response to that is three-fold.

74. First, the difference between spreading the regulatory costs over three years as compared to four years is not significant. The annual cost for a four year amortization period is $109,800 ($450,000 less $10,800 due to a reduction in IR Plan administration costs divided by four). The annual cost for a three year amortization period is $142,800 ($450,000 less $21,600 due to two-years reduction in IR Plan administration costs, divided by three). This $33,000 reduction would be spread over NRG's projected 7,100 customers. Second, NRG is not a large company, and a delay in recouping funds spent on regulatory matters has an impact on the utility's cash flow, particularly if during the amortization period NRG had to expend funds for another rate case. Finally, as a rate-making principle, it is more sound to have the costs match the period that forms the basis for those costs (i.e., if the regulatory costs incurred to establish rates result in a three-year rate setting period, the cost recovery period should match).

(c) <u>Regulatory Costs for the First Year</u>

75. Given that the Board will have to include an amount of regulatory costs in 2011 base rates prior to determining the appropriate term for the IR Plan, NRG would propose that

the Board include an amount for fiscal 2010 based on a five-year amortization period. If ultimately the Board approves a five-year IR Plan some time in 2011 then no adjustment needs to be made. If the Board approves a lesser term, then an appropriate adjustment can be made going forward. For example, should the cost ultimately be recoverable over a three-year period, the balance of the allowed regulatory costs not recovered in the first year (i.e., 80% of the allowed costs) would be recovered in the remaining two years. Hence, if the amortization period is less than five years, the amount recoverable after the first year would increase so as to permit full recovery of the allowed regulatory costs.

F. NRG GAS COSTS FROM A RELATED PARTY

(a) Overview of the Issue

76. NRG purchases natural gas from NRG Corp., a related (but not affiliated) party.

77. In EB-2005-0541, the Board approved a methodology for establishing the pricing for these gas purchases. The methodology set an annual contract price based on the average price of the one-year forward strip price over the last ten business days of September (for a new contract year commencing each October 1st). The methodology also approved the "Source Report" prepared by Energy Source Canada Inc. as the publication to be used as the reference for the one-year forward strip price.

78. NRG's former management neglected to calculate the commodity price for natural gas purchased from NRG Corp. in accordance with this methodology. This was an oversight, as evidenced by the fact that for fiscal 2007, 2008 and 2009, NRG's ratepayers paid slightly less for natural gas than if NRG had used the Board-approved methodology (i.e., for the years 2007, 2008 and 2009, NRG's ratepayers benefited by $71,897).

79. In fiscal 2010, the market price of natural gas dropped significantly. As a result, for the period from October 1, 2009 to April 30, 2010 (1,813,113 m^3), NRG customers have paid $129,807 more for natural gas in that seven month period than if NRG had used the Board-approved methodology. Cumulatively then, failure to follow the methodology for

the past three and a half years has resulted in a small "overpayment" to NRG Corp. of $57,910 (to April 30, 2010).

80. NRG's new management became aware of the oversight (to adjust prices annually) in the fall of 2009 when the significant drop in the market price of natural gas caused the company to examine the pricing from NRG Corp. NRG Corp. was unwilling to sell gas to NRG on the Board-approved methodology. Consequently, it was assumed that NRG would not purchase gas from NRG Corp. for the year commencing October 1, 2009.

81. However, it quickly became apparent that NRG's distribution system needed some gas from NRG Corp.'s wells in order to maintain system stability, prevent line pressure drop and maintain a safe level of odorant in the southern part of NRG's system. The reason for this relates to the historical development of NRG's system. Initially, it was a gathering system from producing wells, but over time has become a significant distribution company. Given the need for the gas, the $71,897 "deficit" in NRG's favour, and the pending rate case, NRG and NRG Corp. agreed to hold the price steady (i.e., at the same level for the past three years) and transact a small amount of gas that would be needed for system reliability (about 2.4 million cubic metres of gas, or about half the normal volumes purchased from NRG Corp.).

(b) <u>NRG's Proposed Methodology</u>

82. NRG's proposed methodology for purchasing gas from NRG Corp. going forward is set out in Undertaking J1.12, and is based on an approach that recognizes the purpose of the gas being purchased from NRG Corp.

83. Consequently, NRG is proposing a methodology that sets a price for: (a) the first 2.4 million cubic metres of gas purchased annually would be deemed required for system integrity ("Integrity Gas"); and (b) amounts of gas purchased over and above this amount ("Non-Integrity Gas").

84. The amount of Integrity Gas is established at 2.4 million cubic metres because that is the expected actual amount that will be purchased by NRG from NRG Corp. this year. This is the best estimate NRG has of required Integrity Gas.

85. NRG's proposal is that pricing for Integrity Gas purchased from NRG Corp. be as follows:

- $8.486 per mcf whenever the "market price" for natural gas is $9.999 per mcf or less; and,
- "market price" for natural gas when gas is $10.00 per mcf or more.

86. The price of $8.486 per mcf is chosen because it was the price agreed to between NRG and NRG Corp. in September 2009 when NRG Corp. advised that it was going to shut in all of its wells due to depressed gas prices. So this amount: (a) represents a price that NRG Corp. will accept in times of depressed natural gas commodity prices; and (b) recognizes that NRG's ratepayers are getting not only natural gas (for system purposes) but also obtaining a benefit from NRG Corp.'s wells (in the form of avoided additional capital assets in rate base). As noted in the response to Undertaking J1.11, NRG's preliminary estimate to address the system integrity via a new pipeline would be at least $1.9 million.

87. To the extent that this pricing proposal for Integrity Gas means that NRG's ratepayers are at risk of paying higher-than-market commodity prices, NRG is proposing to mitigate that risk by providing for an "upside" for NRG ratepayers when the market price for natural gas is between $8.486 and $10.00 per mcf. In that case, NRG's ratepayers would continue to pay $8.486 per mcf. If the price of natural gas went to $10.00 per mcf or higher, then the price paid by NRG for Integrity Gas would be market price. We would propose that the "market price" used in this methodology be determined on the same basis as that set out below for Non-Integrity Gas.

88. With respect to Non-Integrity Gas, the "market price" should be used as the basis for the price to be paid by NRG to NRG Corp. However, NRG is proposing that market price be established in a manner different from that set out in EB-2005-0541.

89. In NRG's view, there were a couple of problems with the previous methodology. First, the Source Report is not reported on a regular or consistent manner as publications from larger companies (e.g., Shell Report). Consequently, NRG proposes that the Board

methodology allow for NRG to base the price on any one of a few specific indexes selected by the Board (including the Shell Report). Second, utilizing the last 10 days of September to set an annual contract price carries risks of being "out of the market" for both NRG and its ratepayers. For example, had NRG used the September monthly average in 2006 instead of the last ten days of September, the $71,897 underpayment by NRG to NRG Corp. would have been a $329,000 underpayment. In other words, the price drop in natural gas over the course of September 2006 alone was enough to more than quadruple the differential over the three year period. This risk can be reduced by adjusting the contract price with NRG Corp. quarterly (coinciding with NRG's QRAM). The contract price would be based on a similar average of the one-year forward strip prices over the last ten business days of the second month preceding the month for which a price would be established (e.g., last ten business days of August for pricing effective October 1).

(c) Treatment of Differential

90. As noted in NRG's response to Board Staff IR#23, it is appropriate that the Board deal with the differential that has arisen as a result of NRG's oversight with respect to the gas cost methodology in EB-2005-0541.

91. If NRG's proposal for the pricing of Integrity Gas is accepted by the Board, then NRG is of the view that there would be no accumulated differential payable either way (either to or from ratepayers).

G. COST OF CAPITAL AND RATE OF RETURN

(a) Overview

92. NRG is requesting a deemed capital structure of 58:42 (debt:equity), and a return on equity ("ROE") that is 50 basis points above the Board-approved ROE. This deemed capital structure and 50 basis point risk premium (0.5%) was approved by the Board in NRG's last rate case (EB-2005-0544).

93. It is NRG's position, and the opinion of its expert (Ms. Kathleen McShane) that the 42% common equity ratio previously adopted by the Board remains appropriate for NRG and an ROE that represents a risk premium of 0.5% above the Board's benchmark ROE is warranted for the 2011 Test Year.

94. All utilities are entitled to earn a fair return (*Northwestern Utilities Ltd.* v. *Edmonton (City)*, [1929] S.C.R. 186 at 192-93). A fair return encompasses the notion that the cost of capital incurred by ratepayers should be equivalent to that which would be faced by the utility raising capital in the public markets on the strength of its own business and financial parameters.

95. The overall cost of capital depends on business risk (i.e., the risk of not earning a compensatory return on the invested capital and failing to recover its invested capital) and financial risk (i.e., risk borne by equity shareholder because the firm uses debt to finance a portion of its assets).

96. Ms. McShane, at lines 203 through 221 of her opinion, outlines the two approaches that can be used to determine a fair rate of return: (a) accounting for differences in business risk through alterations to capital structure while holding cost of equity to a single "benchmark" ROE across regulated utilities; or (b) accepting a utility's capital structure and comparing a utility's total risk against proxy firms and adjusting the cost of equity when setting the utility's ROE. This reflects the linkage between the two components (ROE and capital structure) when establishing a fair return. Both methodologies have been used by the Board.

(b) <u>NRG's Capital Structure</u>

97. In approving an equity ratio of 42% for NRG in EB-2005-0544, the Board commented that the actual equity ratio should be used unless the actual ratio was unreasonable, and that the actual ratio at the time was 41.5%.

98. Since the last decision, NRG has added IGPC as a major new customer on whose behalf NRG has incurred over $5 million in capital expenditures. NRG's rate base has increased by approximately 50% as a result. NRG financed the capital expenditure largely with a

new loan from Bank of Nova Scotia with a principal of $5.2 million. In order to ensure compliance with its debt financing covenants, NRG purchased a GIC.

99. The 2009 year-end capital structure (immediately post-IGPC's addition), measured using total debt net of the GIC plus equity, was 61:39 (debt:equity). Measured on the basis of gross debt, the figures at the end of 2009 are 68:32 (debt:equity).

100. By the end of 2011, NRG's capital structure measured using gross debt and equity is expected to reach 62:38 (debt:equity), and measured on a net debt basis would reach 54:46 (debt:equity). Over the term of the five-year IR Plan, the actual capital structure would average 53:47 (on a gross debt basis) and 43:57 (on a net debt basis). Hence, over the course of the IR Plan, NRG's actual debt:equity ratio will be in the range of its requested capital structure.

101. Further, as Ms. McShane points out at lines 413 to 532 of her opinion: (a) NRG faces no less business risk than at the time of the EB-2005-0544 decision; and (b) there is no evidence that NRG's business risk relative to that of Enbridge Gas has changed materially since that time (the Board has in past cases assessed NRG's risk against Enbridge as the benchmark gas utility).

102. Finally, Ms. McShane compared NRG's capital structure to those adopted for other smaller gas and electricity distributors in Canada (Table 4 of the McShane Opinion, as amended during the oral phase of the proceeding), and determined that the 42% common equity ratio previously adopted by the Board is within the range allowed for other smaller gas and electric utilities.

(c) <u>Equity Risk Premium for NRG</u>

103. As noted above, there is no evidence that the business risk of NRG has declined since the Board adopted a common equity ratio of 42% and an incremental equity risk premium of 0.5% above that applicable to Enbridge Gas (and implicitly 0.5% above that applicable to electricity distributors).

104. Ms. McShane's opinion is that the incremental risk premium (above a benchmark utility) remains appropriate, based on an assessment of the business risk and associated ROEs

for: (a) a proxy group of companies facing a relatively similar level of business risk to NRG; and (b) a proxy group of companies facing a relatively similar level of business risk to the benchmark utility.

(d) <u>OEB's Cost of Capital Report</u>

105. While NRG will wait for the submissions of Board Staff and intervenors, there were a number of questions at the oral phase of the proceeding that sought to clarify NRG's requested capital structure and ROE with the Board's recent *Report on the Cost of Capital for Ontario's Regulated Utilities* (EB-2009-0084, December 11, 2009)("CoC Report"). Consequently, NRG will set out its views on the CoC Report so that Board Staff and intervenors have the benefit of NRG's position.

106. First, as noted at page 50 of the CoC Report, while the Board has established a split of 60% debt, 40% equity as appropriate for electricity distributors, the deemed capital structure for gas utilities is to be "determined on a case-by-case basis". Further, the CoC Report (also on page 50) states that the Board will assume that the base capital structure will remain relatively constant over time and that a full reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk.

107. Second, as noted in the CoC Report, the "fair return standard" is a legal obligation that frames the discretion of every tribunal establishing utility rates. Ultimately, the Board's capital structure and ROE must produce numerical results that provide the utility with a fair return. Thus, notwithstanding the attempt to move to a standardized approach for establishing capital structure (for electricity distributors only) and ROE, the Board must always consider whether the standards in the CoC Report provide the utility with a fair return. To not engage in such consideration and mechanically apply the capital structure and ROE would amount to a fettering of the Board's legal discretion. It flows from this, of course, that every utility has the ability to apply to the Board for a specific capital structure and ROE where the utility believes that the standards in the CoC Report fail to provide a fair return.

108. NRG is of the view that the capital structure and ROE standards set out in the CoC Report do not provide NRG with a fair return, and that there is no evidence on the record in this proceeding that supports deviating from the Board's findings on cost of capital in EB-2005-0544.

H. **COST ALLOCATION**

(a) **Introduction**

109. In this rate proceeding NRG is proposing changes to its existing cost allocation model in order to accommodate the introduction of a new class (Rate 6) and to implement two previous Board Directives. The underlying methodology remains consistent with the methodology used in the NRG cost allocation model previously approved by the Board. The allocation factors have been updated to reflect NRG's current 2011 Test Year load forecast. The fiscal 2011 Test Year allocations are presented in Exhibit G3.

110. The creation of a new rate class was necessary to reflect the connection of IGPC to the NRG system. A new rate class was necessary due to the unique way in which IGPC is served (stand-alone facilities) and IGPC consumption (i.e., the huge increase to NRG's throughput).

111. Board Directives that have, or will have, an impact on the cost allocation model are: (a) the development of a contingency plan to address the reduction and potential elimination of volumes within the Rate 2 class (EB-2005-0544); and (b) a proposal to move to an incremental cost based system gas fee (EB-2008-0106).

(b) **New Rate Class for IGPC**

112. NRG commenced delivery of natural gas to IGPC in the fall of 2008. The costs of the pipeline and related facilities incurred by NRG and proposed to be included in rate base are presented in Exhibit B6, Tab 2, Schedule 1.

113. NRG's approach to allocating costs to Rate 6 is based on the cost causality principle – namely, that a customer or customer class that causes the utility to incur a cost should pay

rates that recover those costs and that no other customer or customer class should bear responsibility for such costs.

114. IGPC is the only customer in the proposed new Rate 6 class. IGPC is served by a dedicated steel, high pressure pipeline that is not integrated with the remainder of NRG's distribution system. Consequently, there are some costs associated with providing service that are directly assignable to IGPC (i.e., costs that are solely attributable to IGPC). In addition, NRG has allocated an appropriate share of common costs to IGPC.

115. During the oral phase of the proceeding, NRG was asked to consider refinements to the cost allocation model so that the unique characteristics of the Rate 6 customer class (most costs are directly allocated) would be reflected more precisely. The first refinement related to a review of the allocation of A&G to consider whether the allocator should exclude Union Gas transportation charges from the component of costs directly assigned to IGPC. The results of NRG's review are set out in the response to Undertaking J2.6. NRG is proposing to modify the cost allocation model to address this issue. The second refinement is the separation of A&G into separate insurance and non-insurance components so that a different allocator could be used for the insurance component of A&G that excludes an allocation to Class 6 in recognition of the direct allocation of the relevant insurance costs to Class 6.

116. The amended allocation impacts insurance costs allocated to IGPC by reducing them from $221,330 to $173,067 (out of a total insurance cost of $284,925). These impacts are shown on the schedule attached to Undertaking J2.6.

117. With respect to insurance, NRG is proposing to allocate to IGPC the following insurance costs:

- 22.5% of property and fleet insurance to IGPC, based on the A&G allocation amendment noted above;

- 40% of the company-wide general liability and umbrella liability insurance to IGPC, based on the insurance letter received from Zurich (attached to Undertaking J1.1);

- allocate 100% of the additional umbrella liability (which although company-wide, is being taken out by NRG solely as a result of the new IGPC assets); and,
- allocate 100% of the business interruption and transfer station insurance (since they are related solely to IGPC).

118. With respect to the additional umbrella liability insurance, although it is company wide (and not restricted to IGPC's assets, such as the business interruption and transfer station insurance), NRG took out this replacement coverage under its existing policy because obtaining a new, additional policy with the same amount of coverage would have been far more expensive.

(c) <u>Decline or Elimination of Rate 2 Class</u>

119. In its EB-2005-0544 Decision with Reasons, the Board directed NRG to consider developing a contingency plan to address possible reduction in Rate 2 volumes (including a potential loss of the entire rate class). NRG's response to the Board Directive is found at Exhibit A1, Tab 4, Schedule 1 of the pre-filed evidence.

120. Volumes of gas delivered to NRG's Rate 2 customer class (consisting primarily of tobacco drying operations) have dropped steadily in the past several years as a result of the decline of the tobacco industry in southwestern Ontario.

121. NRG considers it inappropriate to maintain a customer class if the revenues recovered from that customer class are relatively low (e.g., less than 5% of total distribution revenues) or if maintaining the customer class will result in inappropriately high or unpredictable rates. Application of these criteria suggest that it is appropriate to anticipate the elimination of NRG's Rate 2 customer class.

122. NRG's proposal is to migrate customers from Rate 2 to Rate 4, on the basis that sound rate making dictates that a customer class should consist of homogeneous customers that are heterogeneous versus all other customer classes. Rate 2 customers are most similar to Rate 4 customers (in terms of average monthly consumption levels and patterns). Further, the Rate 2 and Rate 4 customer class eligibility criteria are comparable, as are the level of the currently authorized rates.

123. NRG did examine whether Rate 2 customers could migrate to the Rate 5 customer class, but the consumption levels and patterns are not as similar (when compared to Rate 4), and the Rate 5 customer class has very different eligibility criteria.

124. Absent any other considerations, these criteria support merging customer Classes 2 and 4, and do not support merging customer Class 2 with customer Class 5.

125. NRG is proposing the following orderly process for the reclassification of Rate 2 customers. First, NRG would take steps to close its Rate 2 customer class to new entrants. Concurrently, NRG would advise Rate 2 customers of the ability to transfer to Rate 4, and would transfer any such customers who agree to such transfer. During this process, NRG would strive to maintain comparability between its Rate 2 rates and Rate 4 rates (e.g., under-recovery of allocated costs from Rate 2, if necessary). When the rates are immaterially different, NRG may directly approach any remaining Rate 2 customers to request that they transfer to Rate 4. The customer election period should have a sunset date of 12 to 24 months in the future. After the Rate 2 customers have all been transferred to Rate 4, the Rate 2 class would be eliminated. Elimination of the Rate 2 class in the rate schedule will result in the elimination of the Rate 2 class in the cost allocation model.

(d) <u>Derivation of Incremental System Gas Charge</u>

126. In its Amended Decision and Order, EB-2008-0106, the Board directed NRG to file a proposal to move to an incremental cost based system gas fee (EB-2008-0106, p. 33). NRG's proposal is found at Exhibit A1, Tab 4, Schedule 1.

127. To accomplish this, NRG identified the components of its revenue requirement that were recovered through the System Gas Fee. Each component was identified as common or specifically incurred in connection with the provision of system gas. Any common costs were removed from the system gas revenue requirement by eliminating the functionalization, classification or allocation of costs.

128. Under the proposed $0.000348/m^3 rate, NRG will recover: (a) the return on the portion of the 2011 Test Year Working Cash Allowance related to Gas Commodity (this amount is a credit of $86.0k and reduces the revenue requirement by $7.9k); (b) the 2011 Test Year

income tax expense associated with the Working Cash Allowance ($1.0k); (c) the 2011 Test Year Regulatory and Consulting Fee expenses totalling $15.0 k, representing the costs of QRAM submissions; and (d) $1.1k of assigned Administrative and General Expenses.

129. The revenue requirement totals $8.6k, and is proposed to be applied to projected 2011 Test Year system gas sales volumes to estimate the average incremental System Gas Fee of $\$0.000348/m^3$.

All of which is respectfully submitted this 24th day of September, 2010.

NATURAL RESOURCE GAS LIMITED

By its Counsel, Ogilvy Renault LLP
Per: Richard J. King