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October 13, 2010

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

Dear Ms. Walli:

RE: Natural Resource Gas Limited ("NRG") (EB-2010-0018)
Reply Argument

Please find enclosed NRG's Reply Argument in the above-referenced matter. The Reply Argument is also being filed on the Board's RESS system, and served on all parties to the proceeding.

Please do not hesitate to contact me should you have any questions or concerns.

Yours very truly,

Richard King

/mnm
Encl.

cc. Jack Howley (NRG)
Laurie O'Meara (Ayerswood)
Kathi Litt (ERA)
Heather Adams (Town of Aylmer)
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Paula Zarnett (IGPC)
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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
REPLY ARGUMENT

October 13, 2010

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A. INTRODUCTION

1. This Reply Argument responds to the submissions of Board Staff, the Town of Aylmer (the "Town"), the Vulnerable Energy Consumers Coalition ("VECC") and the Integrated Grain Processors Co-operative Inc. and IGPC Ethanol ("IGPC") on the outstanding (i.e., unsettled) issues in this rate proceeding.

2. These seven unsettled 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

   (7) Cost Allocation

3. NRG also feels it necessary to respond to various unfounded allegations made by the Town and IGPC with respect to the quality of NRG's evidence in this proceeding, which were only raised in argument by these two parties. NRG's response on this is found in the last section of this Reply Argument.

B. CAPITAL COST OF THE IGPC PIPELINE

(a) Overview

4. There are two main issues here: (a) the appropriate amount of the capital cost of the IGPC Pipeline to be closed to rate base (for Rate 6); and (b) the date upon which that amount was closed to rate base.

5. IGPC submits that the amount to be closed to rate base should be $4,744,635 (based on a reduced capital cost of $7,526,353). In addition, IGPC submits that the date for closing this amount to rate base should be no later than August 1, 2008.

6. IGPC also suggests that the amount to be included in rates for the 2011 Test Year should be the mid-Test Year net book value of $4,102,132.

7. NRG submits that the amount to be closed to rate base should be $4,905,251 (based on a pipeline capital cost of $8,626,353). In addition, NRG submits that the appropriate date for closing this amount to rate base should be October 1, 2008.

8. There are a number of specific capital cost items in dispute between IGPC and NRG in relation to the appropriate capital cost of the IGPC Pipeline. The Board has received full submissions on these issues via NRG's initial evidence and information requests, IGPC's motion of August 3rd (and NRG's responding motion materials of August 26th), extensive cross-examination during the oral phase of the proceeding, undertakings, the Argument-in-Chief of NRG and the argument of IGPC. Rather than re-iterate all of these arguments again, NRG will focus on the specific arguments raised in the IGPC argument.

9. It should be noted, however, that this project (which NRG was compelled to build) resulted in significant real costs incurred by a relatively small utility, and the second guessing and potential disallowance of these costs may be easily absorbed in the context of a large gas utility but are critical issues for a small utility.

(b) Proper Approach to Review of Capital Costs

10. IGPC states in their submission (at paragraphs 12 through 16) that: (a) the Board should essentially disregard the initial estimated capital cost of the IGPC Pipeline scrutinized by

the Board at the initial leave-to-to-construct proceeding (EB-2006-0243); and (b) the proper test for capital costs to be included in rates is “reasonable, actual capital costs” as per the Pipeline Cost Recovery Agreement (“PCRA”) entered into between IGPC and NRG.

11. NRG submits that both of these positions are incorrect.

12. The original capital cost estimate for the IGPC Pipeline was $9,100,000. IGPC suggests that this figure is of little value to the Board because it included the construction of a check measurement station, but a check measurement station was never built. IGPC’s counsel apparently discovered this while doing a Google Maps search on the internet. In Undertaking No. J1.3, NRG explained that it was determined that no check measurement equipment was required at the NRG station because one existed at the immediately adjacent Union Gas transfer station and another one at the transfer point between NRG and IGPC (i.e., it was unnecessary so it was not constructed). This would be relevant if the cost of a check measurement station were material, but NRG’s understanding is that such stations are immaterial in terms of cost and there is nothing on the record to suggest otherwise. So this is no reason to consider the initial estimate to be of no value to the Board in its determination of the appropriate capital cost amount of the IGPC Pipeline to be included in rate base.

13. There is another reason why the initial estimate is relevant as well, and that relates to the legal standard of scrutiny to be applied to utility expenditures.

14. In determining the capital costs of a project to be included in rates, the Board is not bound by any contractual test agreed to between utility and customer (as IGPC suggests). Indeed, that was the subject of discussion at the outset of the oral hearing, and the Board clearly understood this:

> MR. SOMERVILLE: My point, though, is that the Board is not bound to the contract as a determination of what the appropriate costs to be included in the capital contribution are. The Board is not bound to that … Parties can enter into any kind of agreement they want.
>
> MR. STOLL: That’s right.

> MR. SOMERVILLE: And the Board is free to use its own methodology, that it has used countless times, to determine what capital – what the cost of the project prudently, reasonably is, and what the – how to calculate the shortfall and how to calculate the aid-to-construct.
>
> OEB Transcript, Hearing Day 1, pp. 97 – 98.

15. The Board's statutory authority with respect to rate-making is to ensure that resultant rates are just and reasonable. Within that, the Board has broad discretion to adopt any method or technique that it considers appropriate in approving rates.[1]

16. In evaluating capital expenditures by utilities, the prudent investment standard has been consistently approved by Canadian and American courts. Under this rule, there is a presumption on the part of the regulator that a utility's expenditures are reasonable and made in good faith. The presumption arises from a very practical consideration – namely, that in the absence of such a presumption, the utility would theoretically have the burden of positively proving, with specific factual evidence, that every cost element in a rate case was reasonable – even where a cost is not at issue. This would be impractical, if not impossible.

17. The classic statement of the prudent investment standard is found in the well-known *Southwestern Bell* case, and has been consistently recognized by utility regulators across North America:

> Every investment may be assumed to have been made in the exercise of reasonable judgment, unless the contrary is shown.
>
> *Missouri ex. rel. Southwestern Bell Telephone Co. v. Public Service Commission*, 262 U.S. 276 (1923) (U.S.S.C.) at 289 ("*Southwestern Bell*").

18. Intervenors can rebut the presumption of management good faith by establishing a *prima facie* case that calls into question the reasonableness of the utility's expenditures. At that point, the burden shifts to the utility to adduce additional evidence to show that the expenditure was reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made (i.e., the Board cannot use hindsight).

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[1] Subsections 36(2) and (3), *Ontario Energy Board Act, 1998* (as amended).

Ontario Energy Board, Decision with Reasons, RP-2001-0029, *Union Gas Distribution Rates 2001-2002*, paras. 2.34 and 2.35 ("Union Decision")

19. The Board has stated in past cases that an intervenor can rebut the presumption by showing:

- that the outcome of the past decision was unreasonably adverse to customers;
- that an inherent conflict of interest exists among the parties to the transaction; or,
- that the utility's conduct was inconsistent with industry practices at the time.

Ontario Energy Board, Decisions with Reasons RP-2001-0032, *Enbridge Gas Distribution Rates 2002*, paras. 3.12.1 to 3.12.5 ("Enbridge Decision")

Burns, R., *Security-Related Cost Recovery in Utility Network Industries*, (Columbus, Ohio: National Regulatory Research Institute, 2003), at 6.

20. In this case, the latter two factors are clearly not at issue: (a) NRG's expenditures on the IGPC Pipeline were not to a related company;[2] and (b) Mr. Grey confirmed under cross-examination that the IGPC Pipeline was constructed in accordance with good utility practice.[3]

21. That leaves the first factor – namely that the outcome of the expenditures on IGPC's pipeline was unreasonably adverse to IGPC. In this context, the initial capital cost estimate of $9.1 million (and the fact that NRG completed the project on time and $500,000 below budget) is a relevant consideration for the Board in its determination of the capital cost of the IGPC Pipeline, particularly given the fact that the original estimate was the subject of consideration at the leave-to-construct proceeding.

22. Consequently, the Board must ask itself, with respect to each expenditure challenged by IGPC, whether: (a) IGPC has rebutted the presumption of prudence; and if so (b) whether the expenditure decision by NRG was consistent with what a reasonable business person

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[2] In the RP-2001-0032 decision, at issue were certain long-term upstream transportation contracts entered into by Enbridge. The presumption of utility prudence in entering into these contracts was rebutted because of Enbridge's equity interest in the upstream pipelines. That is not the case here.

[3] Hearing Transcript, Day 2, page 30, lines 17 to 19.

would have done in the circumstances, at the time the decision was made and given the information available to the utility (i.e., the Board cannot use hindsight).

Union Decision, *supra.*

Southwestern Bell decision, *supra*.

23. The Board can approach the issue of whether the prudence presumption has been rebutted by engaging in a line-by-line itemized review of lawyers' dockets and Mr. Bristoll's time sheets trying to interpret what the entries mean and attempt to hazard a guess as to whether that time was well spent. That is the approach that IGPC is suggesting. In NRG's view, not only is this inefficient and not practical, but such an approach is prone to determinations based on hindsight as each entry is second-guessed.

24. In the alternative, the Board can take a more reasonable, broader approach to the consideration of whether an intervenor has rebutted the presumption. That is by looking at the overall project budget and the resultant costs being claimed by the utility, considering the expenditures complained of in relation to the overall project costs, etc. That is the approach that NRG is suggesting.

25. On that basis, NRG submits that IGPC has failed to rebut the presumption of prudent utility investment. In the event that the Board determines the presumption has been rebutted, NRG submits that the expenditures at issue were all reasonable, in light of the facts and circumstances at the time the project was built.

26. NRG points to three key facts:

- First, as noted, NRG built the IGPC Pipeline on time and under budget. Given that the original capital cost estimate before the Board was $9.1 million and NRG built it for $8.6 million, this certainly should not prompt a regulator to conclude that a full prudence review is required. Quite the opposite, NRG suggests. Had the project been constructed well in excess of the Board-reviewed estimate, a prudence review would have been warranted and NRG would have had to adduce more evidence to justify the prudence of its expenditures. That was not the case here.

- Second, to the extent that overwhelming majority of contested costs are "soft costs" (i.e., legal, regulatory, consulting, etc.), NRG asked that MIG Engineering provide the Board with a sense of the typical level of consulting, legal and administrative costs (as a percentage of total project costs) for analogous pipeline projects (filed at Exhibit C to Affidavit of J. Robert Cowan, Q.C.). As the MIG document demonstrates, 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 (excluding 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). NRG believes that its soft costs on this project are in-line with the 17.5% figure, although IGPC believes the figure is higher (29.86% as per Undertaking J2.3). However, it appears that IGPC has included in soft costs all charges other than materials, prime contractor, insurance and finance fees, interest, and customer transfer station). That means that IGPC includes a number of items that the MIG Engineering letter clearly states would have been extra (i.e., over and above the 17.5% such as the motion costs, the OEB penalty, the contingencies, the land surveyors, regulatory costs, etc.).

- Third, even if the Board accepts IGPC's "soft costs" figures, IGPC (by its own admission) contracted with NRG (in the PCRA) for the right to be intimately involved in every aspect of the pipeline development and construction process.[4] Consequently, the project was not typical for NRG in that NRG could not simply work on a bilateral basis with the contractor (and its subcontractors). IGPC and IGPC's counsel in particular, were consulted and had input into virtually every task involved in bringing the IGPC Pipeline into commercial operation. The example of NRG and its counsel holding weekly conference calls with Aecon, IGPC, IGPC's advisers and the Town of Aylmer <u>even prior to the leave-to-construct proceeding</u> was but one example of the increased administrative burden

[4] See sections 3.9 and 4.5 of the PCRA (at Tab 3 of IGPC's motion materials of August 3, 2010), and OEB Transcript, Hearing Day 2, page 28, starting at line 8.

associated with this project. NRG does not contest IGPC's preference or ability to be involved, but to the extent that this preference resulted in higher than normal "soft costs", that is the reason.

27. Based on this, NRG submits that IGPC has failed to rebut the presumption that the capital costs associated with the IGPC Pipeline were prudently incurred. In the alternative, if the Board is of the view that IGPC has rebutted such presumption, NRG submits that its expenditures were nevertheless reasonable given the circumstances at the time.

(c) Administrative Penalty

28. NRG has included the administrative penalty of $140,000 in the capital cost of the IGPC Pipeline because this cost (if it materializes) is appropriately IGPC's, since the need for the motion that gave rise to the proceeding was unnecessary. IGPC still suggests that this is not the case, but they are wrong. At the IGPC motion of June 29, 2007, counsel for IGPC assured the Board that if the contracts were not signed by NRG, the deal would fall apart:

> MR. KAISER: You're assuring us that if that is not done [ed. note: the signing of the contracts], this money is going back.
>
> Mr. KOVNATS (counsel to IGPC): Yes.
>
> MR. KAISER: Because Canada Trust is obligated legally to send it back and they will send it back? … In other words, I'm trying to get to the practicalities here. If you're telling me that this deal legally is going to fall apart, that's one thing. If it's just an annoyance … that's another thing.
>
> MR. O'LEARY (counsel to IGPC): Sir, we don't believe it is an annoyance.
>
> OEB Transcript, quoted at page 8 of Exhibit F to Affidavit of J. Robert Cowan, Q.C. (emphasis added)

29. The financing did not fall apart as a result of NRG's failure to sign the contracts. By letter to the Board on July 5, 2007, counsel for IGPC advised the Board that the financing of the IGPC Pipeline did not fall apart.[5]

[5] See page 17 of Exhibit F to the Affidavit of J. Robert Cowan, Q.C.

30. NRG had nothing to gain and indeed a lot to lose by not signing the contracts. Nevertheless, at the time, NRG genuinely believed that the only prudent course of action was to take a few more days to ensure its obligations under those contracts did not put NRG's shareholder or ratepayers at unnecessary risk. As noted in our Argument-in-Chief NRG is a public utility and must 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.

31. It was IGPC's lenders that were driving the timeline for contract signing. Unlike NRG, they have no interest in, or obligation to, NRG's other ratepayers.

32. Consequently, unless the Board can expunge the finding and penalty in that proceeding, NRG submits that this amount is properly included in the capital cost of the pipeline.

(d) <u>Legal Costs</u>

33. IGPC makes a number of specific points in its argument related to legal costs, which NRG responds to below. However, the comments above with respect to the increased administrative burden placed on the project as a result of IGPC's involvement is, of course, one of the key drivers for the legal costs associated with the IGPC Pipeline.

34. With respect to the legal costs associated with the appeal of the June 29, 2007 motion, IGPC states that costs associated with re-litigating the Board's decision is inappropriate, and "such appeal is still outstanding more than 3 years later".[6] First of all, NRG believes that IGPC unnecessarily caused this motion and should be responsible for the costs of that motion and any consequent costs (including the penalty and legal costs of appeal). Further, the fact that the appeal has not yet been disposed of by the Divisional Court has not had any further cost consequence. More importantly, NRG perfected its appeal in that matter in the summer of 2007, but the Board and IGPC have failed to file their response to the appeal. It is not NRG that has delayed the Court's hearing of this appeal.

[6] See IGPC's argument, paragraphs 20 to 26.

35. With respect to the legal costs associated with the second motion in February 2008, IGPC incorrectly states that the precipitating event was NRG's demand for $32 million in financial assurance. The real reason for the motion was that IGPC would not provide NRG with a Customer Letter of Credit in accordance with the PCRA, holding to the position that the $5.3 million letter of credit established in the PCRA could not be increased by the Board.. This caused NRG to be delayed in ordering the pipe, components and materials for the IGPC Pipeline. This resulted in the Board (on its own motion) issuing a Notice of Review of the original leave-to-construct decision, and the Board deciding that: (a) it could increase the amount of financial assurance that NRG needed; and (b) ordering IGPC to provide such financial assurance (in this case, directly to Union Gas Limited).[7]

36. There is a larger issue here as well. IGPC seems to be suggesting that legal and regulatory costs of a utility related to business or commercial disputes are always unreasonable or inappropriate business expenses to be included in rates. That cannot be the case. To suggest that utilities must conduct their day-to-day business free of any and all disputes and any regulatory or commercial glitches is unrealistic. There will be business expenses that arise as a result of disputes (with customers, suppliers, government, etc.). As in any dispute, there will be two (or more) views as to who was right and who was wrong. NRG submits that the reasonable approach for a regulator is to look at these disputes and ask whether the costs that the utility incurred were reasonable at the time they were incurred. In the case of both motions, NRG felt that it took prudent steps to protect itself and its ratepayers.

(e) <u>Project Management Fees</u>

37. IGPC contests virtually all of the costs associated with Mr. Bristoll's work on the IGPC Pipeline, on several grounds.

38. With respect to the claim that Mr. Bristoll had no experience with project management of a leave-to-construct application and no experience working for a regulated utility, NRG

[7] See pages 5 and 7 of Board's Decision (EB-2006-0243, March 12, 2008), Tab 11 of IGPC's Motion of August 3, 2010.

has already answered this. The evidentiary record shows that Mr. Bristoll was a Chartered Accountant with significant expertise in the construction industry. In that respect, he had the ideal qualifications and experience to carry out the IGPC Pipeline project. He also had the ability to draw upon (and did, at no cost) the significant expertise of construction executives in companies related to NRG.

39. With respect to Mr. Bristoll's rate, IGPC relies upon provisions in the Accounting Procedures Handbook and notes that while it allows for a utility to include the cost of internal labour, it does not refer to a "market" rate for such labour. With respect, NRG has reviewed the Accounting Procedures Handbook and finds no support for the view that a utility cannot charge appropriate rates for its contract services. Indeed, NRG's Schedule of Services Charges (Exhibit A1, Tab 5, Schedule 2) allows for Contract Work to be provided on a quoted basis. The work done by Mr. Bristoll was more akin to this Contract Work than any other type of work on its Schedule of Service Charges approved by the Board. Moreover, most electric utility's Conditions of Service specifically allow for a utility's overhead costs (including administration) to be added to the capital cost of a project.

40. Given that Mr. Bristoll was completely consumed with this particular project for significant stretches of time, NRG is seeking to be paid for Mr. Bristoll's time at a rate that is appropriate for Mr. Bristoll, and inclusive of overheads. Undertaking JT1.16 sets out the rationale for establishing Mr. Bristoll's rate by benchmarking it to a typical rate that would be charged by someone with Mr. Bristoll's expertise and experience.

41. With respect to the quantum of Mr. Bristoll's time, IGPC contends that it still does not have enough detail on the topic. This is astounding. NRG has provided IGPC with Mr. Bristoll's time sheets, copies of Mr. Bristoll's emails in connection with the project, and then went to the trouble of hiring an auditing firm (Neal Pallett) to carry out an exhaustive analysis of the 1,959 emails to try to substantiate the hours spent during the time when much of the activity on the IGPC Pipeline was carried out. What more does IGPC want? To suggest that this is insufficient is to move the cost justification standard as far away from the rule in *Southwestern Bell* (presumption of utility prudence) as possible.

42. The only anomaly noted in the Neal Pallett review of the 1,959 emails was a duplication of time entry on December 18, 2006, which amounted to a $3,540 reduction in Mr. Bristoll's costs (which NRG had previously agreed to).

43. There can be no doubt about the legitimacy of Mr. Bristoll's time.

(f) Interest

44. IGPC is taking the position that the proper amount of interest to be included in the capital cost of the pipeline is somewhere between $25,000 and $50,000 and that the key to this is that NRG should cease charging interest after July 15, 2008 (when IGPC first took gas), and that to allow a utility to accrue interest thereafter (while collecting distribution rates) would permit the utility to "double recover".

45. NRG's position is that the proper amount of interest to be included in the capital cost of the pipeline is $113,271. This includes two amounts (as set out in detail in Undertaking J1.5): (a) interest calculated from the due date of the Aid-to-Construct invoice to the date the amount was received from IGPC; and (b) interest calculated from the date the last Aid-to-Construct payment was due to the date the final invoice from the primary contractor was received. With respect to (b), this refers to the period during which NRG was financing the construction costs.

46. From a financing point of view, the definition for "during construction" is not when the physical construction was completed but when the final invoices from the contract were received. There is no double recovery here.

(g) Miscellaneous

47. 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.

48. With respect to the Ayerswood amount, IGPC states that there is no information as to what goods or services were provided for this fee. NRG has stated[8] that this amount

[8] Paragraph 35 of NRG's Argument-in-Chief.

related 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.

49. With respect to the Neal Pallett costs, IGPC states that it is unclear what services an auditor would provide that are directly related to the construction of the IGPC Pipeline, and that it appears that they relate to "shareholder taxation issues". They do not. The auditor costs, as previously explained by NRG[9], 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[10].

50. The $62,000 insurance figure represents an allocation of NRG's insurance during the development and construction of the IGPC Pipeline. IGPC objects to this and suggests that insurance should only start to be paid by IGPC once it is receiving gas. NRG submits that that position is unreasonable. Prior to coming into service, NRG had millions of dollars of pipe, components and equipment delivered and was carrying out activities in connection with the development and construction of the IGPC Pipeline. Had any incident happened to the pipe, components and equipment, NRG would have wanted to be insured.

(h) <u>Date for Closing to Rate Base</u>

51. NRG submits that the proper date for closing the IGPC Pipeline to rate base is October 1, 2008. The rationale is that depreciation is supposed to reflect the deterioration of the life of an asset. October 2008 was the commencement of the first full month of gas flow on the IGPC Pipeline and represents the most appropriate date to reflect when the life of the IGPC Pipeline began to deteriorate and asset value began to diminish. Very little gas was consumed in July, August and September of 2008.

[9] Paragraph 36 of NRG's Argument-in-Chief.

[10] See first page of Exhibit E.

C. IGPC PERIOD COSTS

(a) Overview

52. IGPC is also disputing certain period costs that NRG is proposing to include in rates to be charged to IGPC. They are divided into five categories in IGPC's argument: (a) depreciation expenses; (b) insurance expenses; (c) pipeline maintenance expenses; (d) station maintenance expenses; and (e) administrative and general expenses.

53. NRG's response to the arguments raised by IGPC on each of these five issues follows. However, the same legal rule applies to these operations and maintenance expenses as applies to the capital expenditures – namely, that utility forecasts of its costs are presumed to be prudent unless intevenors demonstrate a *prima facie* case as to why such costs should not be included in rates.

(b) Depreciation

54. NRG and IGPC are in agreement on the depreciation rate to be used. What is at dispute is the proper amount to be closed to rate base (and resultant depreciation expense calculated).

55. IGPC's argues that NRG's depreciation expense should be $237,231 (a reduction of $16,419 from that in NRG's application) because the amount sought to be closed to rate base has decreased (see Undertaking J2.4).

56. However, to arrive at this amount, IGPC uses $4,744,635 as the proper amount to be closed to rate base (i.e., with $1.1 million removed from the capital cost of the pipeline). NRG is proposing (in Undertaking J2.4) to close $4,905,251 to rate base.

57. Using the $4,905,251 figure, the depreciation expense is $245,262.55 (a reduction of $8,387.45).

58. This is a mechanical calculation. Whatever the Board determines to be the appropriate amount to be closed to NRG's rate base will dictate the depreciation expense.

(c) Insurance Costs

59. IGPC takes issue with a number of the issues in respect of NRG's proposal to include $173,067 in annual insurance costs in Rate 6.

60. With the addition of the IGPC Pipeline (a 28.5 km, high pressure, steel pipeline) to NRG's gas distribution system, it was clear to NRG (and NRG was advised) that it now had additional operational risk. Quite appropriately, NRG examined its existing liability coverage, and determined after discussions with its insurers that additional coverage was required.[11]

61. As a result, NRG increased its umbrella liability coverage. This was not tendered because it was far cheaper to expand coverage under its existing policy number rather than set up a separate new policy for the additional coverage. NRG believes that this additional coverage was necessary. Further, NRG believes that 100% of this additional umbrella liability insurance be allocated to IGPC since it was only procured as a result of the addition of the IGPC Pipeline.

62. IGPC's position is that it should only bear 40% of these costs, presumably on the basis that the Zurich insurance letter (which IGPC discounts for other reasons, but appears to implicitly favour for the purposes of cost allocation) indicates that 40% of the insurance risk should be allocated to IGPC. NRG has allocated 40% of its base coverage (i.e., the general liability coverage and original umbrella liability coverage) to IGPC. However, for additional insurance (including the additional umbrella liability coverage) triggered solely by the IGPC Pipeline, NRG believes that this amount can only appropriately be the responsibility of IGPC (and cannot be recovered from NRG's other ratepayers).

63. In addition to the additional umbrella liability coverage, NRG purchased business interruption insurance and transfer station insurance.

64. The business interruption insurance is for IGPC only (i.e., it does not cover business interruptions on the entire NRG distribution system, but only on the IGPC Pipeline).[12] If

[11] NRG response to IGPC IR40.

[12] This responds to Board Staff's submission on Issue 7.4.

there were an incident with the IGPC Pipeline, NRG's previous coverage (i.e., without the business interruption insurance) would only cover costs associated with repairing the IGPC Pipeline and any third party damages suffered as a result of the incident. The business interruption insurance allows NRG to recover its fixed costs associated with the IGPC Pipeline.

65. With the addition of IGPC, NRG's customer make-up has been fundamentally altered. NRG now has one customer that takes more gas than all of NRG's other customers combined. The revenues that NRG receives from IGPC are material to NRG's business (projected to be approximately 29% based on Exh. C7/2/4 and C8/2/4). This is unusual for a utility business, and in NRG's view, represents a business risk that any prudent business would mitigate through the establishment of business interruption insurance. Given the size and importance of IGPC to NRG's business, the business interruption insurance is not (as IGPC suggests) for the benefit of NRG's shareholders but for all of NRG's ratepayers. Put simply, NRG believes it prudent to insure against the possibility of an incident immediately wiping out 30% of its revenues for an indefinite period of time.

66. IGPC also states that if the Board does determine that the business interruption insurance is prudent, NRG's shareholder and NRG's other ratepayers are the beneficiaries so they should pay the premium.

67. The question then is: Who should pay for insurance? The entity that creates the risk or the beneficiary of the policy? NRG submits that the most appropriate approach would be to allocate the cost of the insurance to the entity that causes the cost to be incurred (i.e., IGPC) as this is the most consistent with rate-making principles.

68. With respect to the transfer station insurance, IGPC submits that it does not "understand the expenditure of $35,387 to insure a station that cost $884,003 for an amount of $1,785,000" and asks that something less than the $35,387 premium be approved.

69. However, the transfer station insurance covers all the stations associated with the IGPC Pipeline including the stations at either end of the IGPC Pipeline (the Bradley Avenue Station which cost $735,000 and the IGPC customer transfer station noted above) as well

as the Rogers Road station in the middle of the IGPC Pipeline (with shut-off valve, which cost $150,000). Transfer stations are not covered by property and building insurance and the premium is higher than it would be for an office building, due to the nature of the transfer station (i.e., pipe going directly through the station).

(d) <u>Pipeline Maintenance Costs</u>

70. IGPC suggests that the pipeline maintenance costs of $112,109 being proposed by NRG (via a maintenance contract with MIG Engineering) are "unreasonably high and are not caused by IGPC but rather NRG is using IGPC as an excuse to impose such costs."[13]

71. To be clear, these costs are third party costs that NRG will pay to MIG Engineering pursuant to a maintenance contract. This is not a cost for NRG services. NRG makes no money off the maintenance of the IGPC Pipeline. In this context, the above-noted statement does not make sense.

72. IGPC points to the fact that the estimate of incremental operations and maintenance included in the original leave-to-construct application for the IGPC Pipeline was only $38,000. It is curious that IGPC is (on this point) seeking to rely on the estimate in the leave-to-construct application after arguing that the initial capital cost estimate of $9.1 million for the IGPC Pipeline that was considered at the leave-to-construct was to be disregarded.

73. NRG believes that given that the this initial estimate is significantly lower than the current MIG price sought to be included in Rate 6, it is only appropriate that NRG have to justify this significantly larger amount. NRG has sought to be as transparent as possible with respect to the MIG Engineering costs in this proceeding (MIG Proposal contained at Undertaking JT1.6).

74. 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

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[13] Paragraph 58 of IGPC argument.

Pipeline was properly maintained, NRG thought it prudent to have this work carried out by a qualified third party.

75. As noted in its Argument-in-Chief, 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. IGPC does not. NRG personnel reviewed the proposal with MIG Engineering and believe the services outlined to be commensurate with good utility practice.

- NRG believes the maintenance costs associated with the MIG Engineering proposal are reasonable in relation to the capital cost of the IGPC Pipeline ($8.6 million). Annual costs are approximately $112,109 (other costs are one-time or once every several years). This would make the maintenance costs for this facility approximately 1.3% of the capital cost of the facility.

- The MIG letter filed as part of Undertaking J1.14 sets out the general 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. IGPC complains that the legislative requirements cited are too broad (i.e., each item in the maintenance contract is not underpinned by a specific regulatory provision). With respect, a prudent utility does not operate on the basis of minimum legal requirements. In other words, before undertaking a maintenance activity, utilities do not first ask whether they are legally obligated to carry out such activity. They operate in accordance with their best business judgment based on their experience.

- As noted above, NRG has no monetary interest in this contract. NRG's only motivation for incurring these maintenance costs is safety and reliability.

76. IGPC notes that NRG did not tender this contract, and NRG believes that this decision warrants an explanation. 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) because 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.

77. In its argument, IGPC then comments on a number of very specific items in the MIG proposal.

78. With respect to the contention that NRG should use its own employees for the pipeline marking, NRG approached the maintenance of the IGPC Pipeline as a comprehensive program under the control of a competent third party rather than parsing it into bits here and there to be undertaken by a number of parties. That is not an unreasonable approach.

79. With respect to the frequency of pipeline inspections, IGPC is not sure why weekly as opposed to monthly inspections are needed. NRG believes that the weekly inspections are appropriate, and in any event, has no basis for suggesting less frequent inspections. At some point, a company has to be entitled to rely on experts.

80. With respect to the community awareness program, IGPC suggests that it is not clear that the community awareness program was solely the result of IGPC's pipeline. NRG's response to this is that the entire maintenance contract is triggered by and for the sole purpose of the IGPC Pipeline.

81. With respect to the mock emergency training, IGPC makes the curious argument that the annual cost should not be passed on to IGPC because if a third party damages the IGPC Pipeline, the third party should pay. That is a bit like saying one should not have to pay for car insurance premiums, because the person who will rear-end you in two years should pay. That is not a plausible option. Given the nature of the IGPC Pipeline, an incident could involve catastrophic damage. Mock emergency training is a prudent cost.

82. With respect to manual review/technician training, NRG does not agree with IGPC that reviewing maintenance and safety manuals to ensure they adhere to current codes and regulations, and training of NRG staff on the safety manuals relating to the IGPC

Pipeline regarding emergencies are inappropriate costs. Presumably this is maintenance information specific to the IGPC Pipeline and not generic information.

83. With respect to third party observations, IGPC suggests that it should not bear the cost of $4,680 since it should be recovered from the third party that necessitates this work being done. NRG does not bill the developer for third party observations on its main system. NRG is the custodian of the pipeline and it is under NRG's care and control, and as such NRG provides, locates and performs third party observations free of charge.

84. With respect to MIG's costs, IGPC points out that a portion of these costs is to make the pipeline piggable, and that this should be a capital expenditure. The MIG Contract has two costs related to "pigging" – the first is the cost of the in-line inspection which NRG views as an item to be expensed since it is something performed on a periodic basis; the second is a one-time cost of $102,000 to make the pipeline piggable which NRG views as a capital expenditure and has not included in the maintenance costs.

85. Finally, IGPC states that the amount to be included in rates is $35,000. This appears to be based on the initial estimate of the operations and maintenance estimate included in the leave-to-construct application. As noted, on this theory (i.e., adherence to the initial cost estimates), IGPC would accept the $9.1 million capital cost of the pipeline.

(e) <u>Station Maintenance Expenses</u>

86. IGPC states that the maintenance cost of the station is overstated by $3,189 because it includes PST (which was eliminated on July 1, 2010) and that inflation is overstated.

87. NRG agrees with IGPC. As part of the Settlement Agreement (Issue 4.2 on page 13 of 20), there was a PST reduction of $6,960 (of which $3,189 related to the station maintenance contract). NRG will have the cost allocation model reflect this.

(f) <u>Allocated A&G Expenses</u>

88. NRG states that given that the determination of the A&G allocation percentage to IGPC (25.73%) is dependent upon both the costs directly assigned to IGPC as well as other

revenue requirement figures, any change to the costs that are made by the Board would necessitate a re-calculation of the A&G allocation percentage.

89. NRG agrees with this position.

D. DEFERRAL AND VARIANCE ACCOUNTS

(a) Uncontested Items

90. Of NRG's four existing deferral/variance accounts[14], the only issue appears to be the recovery of NRG's legal costs associated with EB-2008-0273 via disposition in NRG's REDA.

91. No party to this proceeding has taken issue with:

- NRG's request to establish an IFRS Deferral Account.
- NRG's request to reset the PGTVA reference price for 2011, and replace the single reference price with two different reference prices (one for rate classes 1 through 5 and one for rate class 6).
- NRG's proposal 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.
- NRG's proposal to assign responsibility for the PGTVA balance by: (a) assigning IGPC its appropriate share of the balance, and developing a fixed charge rate rider; and (b) assigning responsibility to all other customers by assigning responsibility for the remaining PGTVA balance based on volumetric deliveries in the 2010 Bridge Year, and assigning responsibility for the REDA account balance equally to each customer. The net amount will be recovered from each

[14] NRG's four existing accounts are: (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").

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.

(b) <u>REDA Disposition of NRG Legal Costs in EB-2008-0273</u>

92. NRG proposes to dispose of a REDA balance of $173,907, of which $111,123 relates to NRG's own legal expenses to defend an application brought by Union Gas Limited ("Union") to discontinue service to NRG in EB-2008-0273.

93. Board Staff and VECC have focused on the very specific wording at page 7 of the Board's Decision in that case, which states:

> In the case of Union's request for security, NRG did not act in a timely manner. The record suggests that NRG essentially stone-walled Union. **This resulted in significant costs for Union, the Board, the Town of Aylmer and the Integrated Grain Processors Co-operative.** This type of brinkmanship is not helpful where 6,500 customers and a recently activated ethanol plant supported by substantial Federal and Provincial funding are involved. **The Board also directs that costs being paid by NRG shall be paid by NRG's shareholder and not passed on to the NRG rate payers.** (emphasis added)

94. At issue is whether the "costs" referred to in the final sentence of the excerpt above refer to: (a) the costs of Union Gas Limited, the Board, the Town of Aylmer and IGPC; or (b) the costs of Union Gas Limited, The Board, the Town of Aylmer, IGPC, <u>and also</u> NRG's own legal expenses associated with the hearing.

95. Board staff and VECC suggest that the wording from EB-2008-0273 quoted above is "clear" in its meaning that "costs" was to include NRG's legal expenses in addition to the Union, Board, Town and IGPC costs. VECC goes further to argue that even if it was not clear, NRG's expenses were imprudently incurred.

96. NRG disagrees with both of these arguments. First, NRG believes that the correct interpretation is that the Board meant that only the costs of Union, the Board, the Town and IGPC should be borne by NRG's shareholder. Second, NRG believes the costs were absolutely prudently incurred.

(c) Correct Interpretation of EB-2008-0273

97. NRG submits that there are two approaches to interpreting any portion of a tribunal decision: (a) a literal approach (i.e., what does the plain meaning of the text suggest); and (b) a contextual approach (i.e., do the circumstances make a particular interpretation more plausible).

98. From a literal perspective, the excerpt noted above is clear. The paragraph first uses the phrase "costs" to mean "costs for Union, the Board, the Town of Aylmer and the Integrated Grain Processors Co-operative". The only other use of the term "costs" in that paragraph is one sentence later, wherein the Board directs that these "costs being paid by NRG be paid by NRG's shareholder". NRG submits that these latter "costs" are exactly the same "costs" that the Board references earlier in the same paragraph (i.e., the Union, Board, Town and IGPC costs).

99. A contextual interpretation only serves to support the literal interpretation. The excerpted paragraph is from the costs award section of the Board's Decision in EB-2008-0273. The costs incurred by a utility in a proceeding are never the subject of consideration in a cost awards section of the Board. When the Board adjudicates upon cost awards, they typically mean costs awarded to intervenors. There is nothing in the EB-2008-0273 Decision to suggest that the Board meant something else.

100. There is further context to support an interpretation that the Board's Decision was only meant to require NRG's shareholder to bear the costs of Union, the Board, the Town and IGPC. As noted in NRG's Argument-in-Chief, the normal civil litigation rule is that if a party declines a settlement offer and the court-ordered outcome does not exceed that settlement offer, the party that declined the offer will bear the costs of the proceeding. In the EB-2008-0273, there were five possible outcomes that the Board could have ordered (declining in severity): (a) discontinue service to NRG; (b) order NRG to post financial assurance with Union; (c) order NRG to change its contractual start date with Union;[15]

[15] Union Gas had sought to move NRG from an October 1 contract start date to an April 1 contract start date, as Union has sought to do with many customers. As noted in the EB-2008-0273 at footnote 1, page 3: "NRG supplies gas to Union in firm, daily, even quantities throughout the year. However, NRG takes gas from Union according to daily and monthly demand. That demand is greatest during the winter heating season. That means that by the end of the heating season on March 31st, NRG owes Union Gas in an amount valued at approximately $1.9 million dollars.

(d) order NRG's shareholder to postpone the retractable feature of NRG's common shares; or (e) deny any relief.

101. NRG refused to negotiate with Union about (a), (b) or (c), but did offer to postpone the retractable feature of NRG's shares. This offer was made on the record in EB-2008-0273. Union refused to accept this offer (again, on the record in EB-2008-0273). Ultimately, the Board declined to order service discontinuance, financial assurance or a change in contractual start date. The Board ordered exactly what NRG freely offered, and what Union explicitly rejected.

102. The Board has no specialized expertise in the field of cost awards, yet departed from the general rule applicable to costs by ordering NRG's shareholder to pay intervenor costs in EB-2008-0273. In any event, NRG's shareholder paid these costs.

103. The interpretation now being suggested by Board Staff and VECC is that NRG's shareholder should also pay NRG's legal expenses for defending Union's unsuccessful application. This, in NRG's view, would compound an incorrect and unsupportable decision.

(d) <u>Prudence of NRG's Legal Expenses in EB-2008-0273</u>

104. The prudence of NRG's expenses to defend Union's application is almost beyond question. Union brought an application to discontinue service to NRG (or in the alternative, obtain financial assurance from NRG or have NRG switch its contract start date with Union). At the start of the oral proceeding in EB-2008-0273, Union stated that it would not seek to discontinue service, but was pursuing financial assurance or an altered contract start date from NRG. Both forms of relief would have imposed significant costs on NRG's ratepayers.

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

Changing the renewal date to March 31st would mean that the balance would have to be zero at that date. This would reduce Union's liability and would impose a one time gas cost on NRG. The practical impact of such a change to the contract start date is that instead of NRG drafting Union's system, NRG would be in a position of having "over-delivered" gas to Union (because NRG delivers its annual contractual gas commitment evenly over 365 days)."

- 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 in 2006 that required retractable shares to be reported differently on financial statements; and,

- to the extent that the retractable nature of the shares was the source of concern about NRG's overall health, the retractable nature of the shares had already been postponed to NRG's bank (i.e., they could not be retracted).

106. Based on concerns about the costs and merits of Union's requested relief, NRG did not entertain requests by Union to post financial assurance or change its contract start date with Union. Other "lesser" relief such as further postponement of NRG's shares was unacceptable to Union (as was stated on the record in the EB-2008-0273). A hearing was inevitable. It was not the result of "stonewalling" on the part of NRG, but rather because NRG did not want to provide Union with a financial assurance or change its contract start date, and Union would accept nothing less.

107. The result of the hearing is that NRG did not have to post financial assurance or change its contract date with Union. This is of benefit to NRG's ratepayers.

108. How then, does VECC conclude that incurring these costs were imprudent? NRG was protecting its shareholder and ratepayers from an unreasonable request. It should not be punished for doing so.

E. APPROPRIATE AMORTIZATION PERIOD FOR REGULATORY COSTS

(a) Overview of the Issue

109. Only VECC has made submissions on this issue. Although VECC's submission suggests that the parties have very divergent views on the issue, NRG does not believe that to be the case. NRG does, however, believe that VECC's submission reflects a misunderstanding of NRG's position. The purpose of NRG's reply submission to clarify the issue for the Board Panel.

110. Here is what NRG understands to be <u>not</u> at issue:

- As part of the Settlement Agreement, the parties agreed to allow NRG to recover $450,000 in regulatory costs through rates. A component of this ($54,000) was for future administration of the Incentive Regulation ("IR") Plan.

- The Settlement Agreement was premised on the $450,000 being amortized over five years (i.e., $90,000 per year), which matched the term of the IR Plan being proposed by NRG.

- While the parties agreed to settle the regulatory costs for inclusion in rates as part of the Settlement Agreement, the parties did not reach settlement on the IR Plan.

- Towards the end of the oral phase of the hearing, NRG agreed, with the support of the parties, to defer consideration of the IR Plan to Phase 2 of this proceeding. This would allow everyone (NRG and intervenors) to have the benefit of established base year rates to work from when negotiating on the IR Plan.

- NRG did not withdraw its IR Plan evidence in this case. It only withdrew its request for the Board to make a determination on the IR Plan evidence as part of its Phase 1 Decision.

- Once the Board issues its Phase 1 Decision (and base year rates are established), NRG and intervenors will commence discussions on the IR Plan. Failing a negotiated settlement on an IR Plan, NRG will come forward with an IR Plan as part of Phase 2 of this proceeding.

111. Here is what NRG understands to be the positions of the two parties:

- NRG: For the 2011 Test Year, NRG is proposing that $90,000 of regulatory costs be included in rates. For subsequent years, the amount of regulatory costs to be included in rates annually is dependent upon the outcome of Phase 2 of this proceeding. If a **five-year IR Plan** is approved (either through settlement or Board Decision), then NRG's view is that $90,000 of regulatory costs should be recovered in each of years 2 through 5 of the IR Plan. If a **four-year IR Plan** is approved by the Board, then NRG's position is that $116,400 in regulatory costs should be recovered in each of years 2 through 4 of the IR Plan. This is calculated by taking the $450,000 in regulatory costs agreed to in the Settlement Agreement, reducing it by the $90,000 collected in the base year, and reducing it by a further $10,800 in IR Plan administration costs (as specifically set out in the Settlement Agreement), and dividing this amount ($349,200) over the three remaining years of the IR Plan. If a **three-year IR Plan** is approved by the Board, then NRG's position is that $169,200 in regulatory costs should be recovered in each of years 2 and 3 of the IR Plan. This is calculated by taking the $450,000 in regulatory costs agreed to in the Settlement Agreement, reducing it by the $90,000 collected in the base year, and reducing it by a further $21,600 in IR Plan administration costs (as specifically set out in the Settlement Agreement), and dividing this amount ($338,400) over the two remaining years of the IR Plan. If **no IR Plan** is approved by the Board, then NRG's position is that $153,000 in regulatory costs should be recovered in each of the two years following the 2011 Test Year. This is calculated by taking the $450,000 in regulatory costs agreed to in the Settlement Agreement, reducing it by the $90,000 collected in the base year, and reducing it by a further $54,000 in IR Plan administration costs (as specifically set out in the Settlement Agreement), and dividing this amount ($306,000) over the two fiscal years subsequent to the 2011 Test Year.

- VECC: VECC's approach is to proceed from the starting position that this is not a multi-year rate case, and that as a result, all the IR Plan administration costs should be removed from the regulatory costs to be included in NRG's 2011 Test Year rates (i.e., $450,000 less $54,000). VECC would then recover $99,000 in rates over four years (i.e., the 2011 Test Year and the three subsequent years). If a five-year IR Plan is approved by the Board, then VECC would "add back in" the $54,000 in IR Plan administration costs by adding $13,500 to the regulatory costs in years 2 through 5 of the IR Plan ($54,000 divided by four).

112. NRG's position and VECC's position start from two different premises.

113. VECC's position starts from the premise that when the IR Plan was deferred to Phase 2 of this proceeding, this application became a single year cost-of-service application. It did not. NRG did not withdraw its IR Plan evidence. This proceeding will not end (and Board docket number will not close) when the Board issues its Phase 1 Decision. NRG has merely (for the benefit of NRG and intervenors) decided to defer the IR Plan issue until the base year rates are set. By starting with this false premise, VECC's includes in base year rates one-quarter of the agreed-upon regulatory costs (less all of the IR Plan administration costs). This would mean $99,000 in regulatory costs in the base year, according to VECC's proposal. VECC's proposal then has a contingency that would (in the event that the Board approved a five-year IR Plan) add one-quarter of the $54,000 in IR Plan administration costs to rates in each of years 2 through 5 of the IR Plan.[16]

114. NRG's position starts from the premise that we are still in a proceeding that will see the Board render a decision on a multi-year IR Plan for NRG. NRG is not seeking include $132,000 of regulatory costs in base year rates (as suggested by VECC's argument). In fact, NRG's proposal is to include only $90,000 of regulatory costs in base year rates. In NRG's view, this is more consistent with the evidentiary basis of the proceeding, the IR Plan evidence that has not been withdrawn by NRG, and the fact that there will be a Phase 2 Decision. If a five-year IR Plan is approved, then the regulatory costs to be included in rates in years 2 through 5 of the IR Plan would continue to be $90,000.

[16] It should be noted that one complication in VECC's proposal is that because they would include $99,000 in rates in the base year, one of two things would have to happen if a five-year IR Plan were approved (leaving aside adding back $54,000 in IR Plan administration costs): (a) the $99,000 included in base rates would be continued in years 2 through 4 (but be zero in year 5) of the IR Plan, since the full amount would have been recovered by the end of year four; or (b) the amount included in base rates would drop to $74,250 for years 2 through 5 (because the $99,000 is based on a four-year amortization period not a five-year amortization period).

115. At the end of the day, both NRG's proposal and VECC's proposal would yield the same result if the Board approved a five-year IR Plan or a four-year IR Plan. The only issue arises between the parties if the Board approves an IR Plan that is three-years or shorter (or refuses to approve an IR Plan). This, NRG submits, is the only issue truly in dispute. If this issue arose, NRG's position is that whatever regulatory costs NRG is entitled to (pursuant to the Settlement Agreement) should be amortized over the remaining two years following the base year (i.e., a three-year amortization period), whereas VECC's position is that such costs should be amortized over the next three years following the base year (i.e., a four-year amortization period). This was clearly articulated in the Settlement Agreement:

> ***In the event that the Board does not approve a five-year IR Plan, the parties do not agree on the appropriate amortization period for the regulatory costs. Thus, if the Board approves a five-year IR Plan, then this Issue 4.4 is completely settled. If the Board approves an IR Plan for NRG that is shorter than five years, then the parties agree to have the Board determine the issue as to the appropriate amortization period for the regulatory costs.*** (emphasis in original)

116. As set out in NRG's Argument-in-Chief, NRG's position is that a three-year amortization period is appropriate for three reasons. First, the annual regulatory costs that would result are not significant. Second, NRG is a small 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).

117. There is, of course, another option. There is no need for the Board to determine this specific issue in its Phase 1 Decision. Indeed, a Board determination on this issue in its Phase 1 Decision would be moot if the Board approved a four or five-year IR Plan in Phase 2. The only issue the Board absolutely needs to determine in Phase 1 is what amount of regulatory costs to include in base year rates. On this point, the difference between VECC's position and NRG's position is only $9,000. NRG believes inclusion of $90,000 in rates in the 2011 Test Year is more appropriate because it is more consistent with the evidentiary record and issues outstanding.

F. NRG GAS COSTS FROM A RELATED PARTY

(a) Overview

118. Only Board Staff provided substantive submissions on the issue of the pricing for NRG's purchases of natural gas from NRG Corp. (a related, but not affiliated, party).

119. There are essentially four issues to be addressed as a result of Board Staff's submissions: (a) What is an appropriate pricing methodology to be used for NRG's purchases of natural gas from NRG Corp.'s producing wells? (b) Should there be a refund of $97,000 to NRG ratepayers as a result of failure to adjust the price of gas since 2007? (c) Should NRG charge a transportation rate of $0.95 per mcf and an administrative charge of $250 per month for every month the NRG distribution system is used by NRG Corp. to transport gas? (d) Should NRG be directed to prepare an engineering study aimed at solving the system integrity issue, and if so, who should pay? (e) Should the Affiliate Relationships Code ("ARC") be deemed to apply to the relationship between NRG and NRG Corp.?

(b) Appropriate Pricing Methodology

120. Board Staff rejects NRG's proposed pricing methodology, and states that a single price (either Union's Landed Reference Price or the price based on a published market index) is more appropriate.

121. NRG finds Board Staff's rationale (as set out in its submission) to be somewhat inconsistent.

122. NRG's proposed pricing methodology was based on the following facts: (a) neither NRG nor the Board can force any supplier (including NRG Corp.) to sell gas to NRG (i.e., ultimately this is a decision made by every supplier based on price); (b) NRG nevertheless had to have NRG Corp.'s wells injecting a minimum amount of gas (estimated at 2.4 million cubic metres annually) into NRG's system for system integrity reasons ("Integrity Gas"); (c) NRG and NRG Corp. had recently been forced to negotiate

a price during a period when NRG Corp. was unwilling to sell gas to NRG because the price offered by NRG was too low in NRG Corp.'s view; (d) the negotiated price agreed to was the existing price of gas that had been used in fiscal 2007, 2008 and 2009; (e) NRG ratepayers enjoy (and have enjoyed for years) a substantial benefit as a result of having NRG Corp. carrying out natural gas exploration, development and production in NRG's southern service area (because these wells enable NRG to maintain system integrity with a smaller asset base than would otherwise be required).

123. Based on these facts, NRG devised a pricing methodology, the conceptual underpinnings of which were: (a) a baseline price for Integrity Gas set at the negotiated amount agreed to when NRG needed NRG Corp. to produce and NRG Corp. was initially unwilling to produce; (b) a recognition that this baseline price encompasses the benefit to ratepayers from having NRG Corp. wells producing in NRG's southern service area; (c) an "upside" for ratepayers that would allow them to purchase natural gas at a below-market price of \$8.486 per mcf when the market price was between \$8.486 per mcf and \$10.00 per mcf; (d) market-based pricing based on a published index when natural gas pricing is above \$10.00 per mcf; and (e) market-based pricing based on a published index for all Non-Integrity Gas (i.e, gas over and above 2.4 million cubic metres annually).

124. NRG proposed this methodology because it viewed these conceptual underpinnings as fair to ratepayers while at the same time allowing NRG to operate its system in the most efficient manner possible. NRG also submits that conceptual underpinnings are transparent and constitute appropriate rate-making.

125. NRG also proposed that instead of adjusting the price of gas purchased from NRG Corp. on an annual basis, that the price be adjusted on a quarterly basis. This results in less volatility for both NRG and its ratepayers that utilize system gas. Board Staff agrees with this.

126. Board Staff, however, does not agree with NRG's proposed pricing methodology.

127. NRG finds Board Staff's reasons for rejecting the proposed methodology inconsistent because Board Staff states that at first glance, the proposal appears reasonable. Presumably it appears reasonable because Board staff sees merit in the conceptual

underpinnings of the methodology (i.e., recognizing the system benefit of Integrity Gas, providing for rate mitigation measures for ratepayers, etc.). However, Board Staff then states that because natural gas prices are expected to remain low in the medium term, the whole methodology should be rejected and NRG should simply use a market price for all gas.

128. A single market-based price for all gas does not recognize the benefit that has accrued to ratepayers for years as a result of having NRG Corp. wells producing in the southern service area. It does not recognize that NRG cannot compel NRG Corp. to sell gas at any price. Nor can the Board compel NRG Corp. to sell gas to NRG. In times of low natural gas prices, NRG Corp. could simply shut in its wells and wait for prices to rebound before selling again (as could any supplier). Without spending a significant amount of money on a new pipeline (estimated roughly at $1.89 million), NRG and its ratepayers cannot tolerate NRG Corp. shutting in its wells.

129. The reality is that the wells producing the Integrity Gas provide a benefit to NRG and its ratepayers that outweighs the cost. It has provided this benefit for years, and only in the past 12 months have gas prices dropped to a level at which NRG Corp. is no longer willing to accept the market price (i.e., the price has dropped such that NRG Corp. has determined that it would shut in its wells). When that happened, NRG and NRG Corp. negotiated in good faith and agreed to maintain the price that had been used since 2007. It is worth noting that the price that had been used since 2007 was below market price for that entire time period.

130. NRG submits that its pricing methodology is sound, workable and transparent. Based on Board Staff's view that the proposal initially seemed reasonable, one would have expected Board Staff to tweak the pricing (if Board Staff were concerned that the baseline was too high in the near term) or suggest another methodology that is consistent with the conceptual underpinnings that it initially found sensible.

(c) Whether to Provide a Refund

131. This issue arises because NRG's former management neglected to calculate the commodity price for natural gas purchased from NRG Corp. in accordance with the

methodology established in EB-2005-0544. This was an oversight and not anything untoward, as evidenced by the fact that for fiscal 2007, 2008 and 2009, NRG's ratepayers paid less for natural gas than the market price of natural gas. By the end of fiscal 2009, a benefit of $71,897 had accrued to ratepayers in the form of lower gas commodity prices.

132. 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, 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).

133. Whether or not to provide a refund, NRG submits, should be entirely dependent upon the Board's determination of the appropriate pricing methodology governing natural gas purchases between NRG and NRG Corp. If the Board adopts NRG's proposed pricing methodology then no refund should be made to ratepayers, because inherent in the Board's approval is recognition that the current price is an appropriate baseline price. If the Board adopts Board Staff's suggestion that a single market-based price be used even in low gas price periods when NRG Corp. is unwilling to sell, then a refund should be made to ratepayers in accordance with the mechanics set out in Board Staff's submissions.

134. Approaching the issue this way ensures that gas purchases since 2007 be treated consistently with how the Board determines future gas purchases should be governed. In other words, if the Board determines that the appropriate methodology is the one proposed by NRG, then applying that methodology back to 2007 would mean no refund to ratepayers. If on the other hand the Board determines that the appropriate methodology is the one put forward by Board Staff, then applying that methodology back to 2007 would mean a refund to ratepayers.

(d) <u>Transportation Costs</u>

135. Board Staff submits that NRG charge NRG Corp. a transportation fee (based on the Greentree Gas & Oil Ltd. charges filed in this proceeding) for gas sold by NRG Corp. into Union's system.

136. NRG has no issue with Board Staff's suggestion.

137. One thing should be noted, however. NRG would not be forecasting any revenues from these transportation charges. The last time NRG Corp. sold gas to Union was in 2007. Prior to that, NRG Corp.'s sales to Union were minimal and sporadic. NRG understands that NRG Corp. does not expect to sale gas to Union in the near- to medium-term. So until such time as there is a basis for revenues to be included in NRG's rates, the establishment of an NRG transportation charge will provide NRG ratepayers with no ratepayer benefits. In fact, the past sales of gas from NRG Corp. to Union have always been so minimal and sporadic that it is unlikely NRG would ever forecast any revenues from these charges. Consequently, Board Staff's view that failure to have an established transportation rate has deprived NRG ratepayers of $31,297 in offsetting revenue has to be viewed in this light.

(e) <u>Preparation of an Engineering Study</u>

138. NRG's distribution system needs a minimal amount of gas from NRG Corp.'s wells to be injected into the distribution system (approximately 2.4 cubic metres of gas annually or about 7% of NRG's throughput) in order to maintain system stability, prevent line pressure drop and maintain a safe level of odorant. 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.

139. NRG was asked during the oral hearing to advise what physical changes to NRG's system would be required to "solve" this system integrity issue (i.e., to allow the system to operate with zero flow from NRG Corp.'s wells). Based on a very preliminary estimate, NRG determined that a new pipeline would be required to the southern district at a cost of $1.89 million. Excluding regulatory, financing and land acquisition costs (Undertaking J1.11).

140. Board Staff suggests that a formal engineering study be prepared to canvas all possible options to solve the problem. Further, Board Staff suggests that NRG's shareholders and not NRG's ratepayers should pay for the study. Board Staff's rationale for requiring NRG's shareholder to pay is tied to a wholly unrelated issue; namely, that NRG has not charged NRG Corp. a transportation rate in years past, so NRG ratepayers have been deprived of the benefit of transportation revenues (in the amount of $31,927) to offset costs.

141. NRG has two responses to these issues.

142. First, if the purpose of Board Staff in these proceedings (i.e., where there are public interest intervenors already participating) is to ensure the Board Panel has a complete record before it, and to highlight the costs and benefits of various decision options, one would have expected a more even-handed approach to this issue from Board Staff. Board Staff has worked hard to find a benefit to NRG's related company to justify imposing the cost of the study on NRG. Board Staff has completely ignored the fact that the real beneficiary of the system integrity issue has been ratepayers, and this benefit has accrued to ratepayers for years. The fact is that NRG's ratepayers have benefited by having a materially smaller asset base for years as a result of NRG Corp.'s gas exploration, development and production activities. This benefit is at least roughly quantifiable, based on the information on the record about what it would cost to solve the problem. A $1.89 million "solution" would provide NRG with a return on equity of close to $80,000 in the first year (at NRG's current capital structure). This far outweighs the $31,927 in foregone transportation costs (which is over a six year period – i.e., $5,200 per year), even assuming the transmission revenues could have been recouped. Consequently, NRG submits that if a study is required, its cost should be paid for by ratepayers.

143. Second, the Board should carefully consider whether such a study is necessary (i.e., whether the benefits outweigh the costs of the study). Given that the costs of such a study are unknown, NRG submits that the Board should consider whether NRG should first obtain and submit quotes on the prices to carry out such a study, perhaps to be brought forward for consideration in Phase 2 of this proceeding. This approach would not have to impact NRG's base year rates.

144. In the alternative, the Board could ask NRG to have the expert report prepared but as noted above, NRG submits that these costs be borne by ratepayers.

(f) <u>Deemed Applicability of ARC</u>

145. Board Staff wants the ARC to be deemed to apply to the NRG/NRG Corp. relationship.

146. NRG has never taken issue with the Board's scrutiny of the contractual relationship between NRG and NRG Corp. (governing the sale of gas) as if it were an affiliate transaction. Board Staff's proposal would have all of the obligations in the ARC apply to the relationship between NRG and NRG Corp.

147. NRG submits that this is unnecessary, for a few reasons. First, as noted above NRG has no issue with the de facto application of the affiliate transaction provisions of the ARC applying to NRG's purchase of gas from NRG Corp. in rate proceedings. Second, NRG is a small utility and believes that if additional regulatory requirements (i.e., those that otherwise do not apply) are to be placed on a small utility, there should be a justifiable benefit. The problem with a blanket application of the ARC is that the various obligations in the ARC are drafted to address a number of potential dangers including: (a) preventing utility affiliates from obtaining confidential customer information from a utility (i.e., privacy concerns); (b) preventing utility affiliates from obtaining operational information from a utility that would give the affiliate a competitive commodity trading advantage (as compared to unaffiliated trading companies) (i.e., a commodity market fairness issue); and (c) requirements governing shared corporate services between an affiliate and a utility (i.e., a cost allocation issue). The ARC provisions dealing with these issues would, if Board Staff's submission was accepted, be applicable to NRG with no real benefit to NRG or its ratepayers.

148. The proper concern of the Board as regards the relationship between NRG and NRG Corp. is that an appropriate price be established for the purchase of gas (i.e., it is an affiliate transaction concern). The Board deals with this issue at NRG rate proceedings, and NRG never objects to the Board's ability to do so. Further, if the Board approves the proposal of NRG and Board Staff (opposed by no other party to the proceeding) that the contractual price be adjusted quarterly as part of NRG's QRAM process), then the Board

will have full disclosure on the pricing arrangement between NRG and NRG Corp. in a quarterly Board proceeding.

149. The Board, as far as NRG understands, has no other concerns with the relationship that would be cured by the other provisions of the ARC. Further, Board Staff's submissions do not reveal any concern that needs to be cured via application of the ARC. Instead, Board Staff simply states that the Board has deemed such relationships in the past. The fact that there is precedent for deeming ARC applicability does not mean that it should be done absent any good reason. No party has offered any reason.

G. COST OF CAPITAL

(a) Overview

150. 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).

151. 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.

152. A number of parties to this proceeding made similar arguments with respect to capital structure, ROE and cost of debt, which NRG responds to below. However, NRG does have some preliminary comments about cost of capital.

153. There is something unsettling in the premise that a utility can: (a) be statutorily compelled to connect a new customer that will double the utility's asset base; (b) be expected to finance that customer connection; (c) be criticized for having increased their debt load; and (d) face arguments that as a result, the utility's return (which is supposed

to be reflective of risk) should be reduced. Yet that is the premise underlying the arguments of the intervenors and Board Staff in this proceeding.

154. The second preliminary comment relates to the notion that somehow NRG could "cure" this debt problem as a result of injecting equity into the company. This reflects a lack of understanding as to how small private utilities operate. Ontario has very few of these, as most non-municipal utilities are either large in size (Enbridge and Union) or part of a larger energy family of companies (Fortis and Brookfield). The actual level of equity (in relation to rate base) in a company such as NRG will vary based on two factors: (a) the company leaving retained earnings in the company between dividend payments; and (b) the level of debt outstanding on loans. Equity injections are atypical. For example, prior to NRG's last rate case, NRG's shareholder had taken no dividend for several years and as a result the actual equity (relative to rate base) was over 70%. Even after a significant return of paid-up capital to the shareholder in 2006 (of over $2 million), the actual equity level remained at 41.5%. With the addition of the IGPC Pipeline to NRG's rate base, NRG's actual equity has understandably dropped and will be built up again via the accumulation of retained earning and the earnings derived from the IGPC pipelin.

155. The third preliminary point relates to the retractable shares of NRG. In NRG's view, this really is a red herring issue. As NRG has stated before, the issue arose as a result of a change in accounting rules. The shares had been retractable for years prior to that rule change. The nature of the equity in the company has not changed. Further, the retractable nature of the shares has effectively been removed by their postponement not once (to NRG's lenders) but twice (to Union Gas as well). The Town argues that the retractability may be postponed in favour of these two parties but not other parties (i.e., not NRG ratepayers). But there is nothing to this argument. NRG's shareholder cannot retract the shares as long as: (a) it is borrowing money (i.e., if it fully paid off all its Bank of Nova Scotia loans the shareholder can retract); or (b) it is in a position of owing amounts to Union Gas Limited. The fact is that in practical terms, NRG is not going to move to eliminate all debt (i.e., become a 100% equity company), so for as long as the shares are retractable they will be postponed to the bank. Second, because NRG's contract start date with Union Gas is October 1, 2010, it drafts Union's system (i.e., uses more gas at the front end of the contract year and then moves back towards balancing its

position by contract year end), so the postponement in favour of Union is also not temporary in nature.

156. Finally on this point, the approach of the Board in NRG's last rate case was to adopt NRG's actual capital structure because it was reasonable (i.e., it would only deem a capital structure if it were unreasonable). It would obviously be unreasonable to deem a capital structure with zero equity. So consideration of the issue is of little value. Ms. McShane, when asked to hypothetically consider NRG having no actual equity opined that a reasonable outcome would be a deemed capital structure in the range for 60:40 to 52:48.[17]

157. Nevertheless, NRG has heard the concerns of parties and past Board Panels about the retractable shares and as noted at the hearing will make sure that the issue is dealt with in the near term and is currently working on having the retractable feature of the shares removed.[18]

158. The sections below deal with the specific arguments made by intervenors and Board Staff with respect to cost of capital.

(b) <u>Capital Structure – NRG's "Actual" Equity Generally</u>

159. Some parties suggest that NRG's actual equity is currently 37% and since the Board used the actual equity to establish capital structure in NRG's last rate case, it should use 37% this time as well. They argue that it is not appropriate to look at how NRG's actual equity will change over the next five years for the purpose of setting base year rates, particularly given the fact that NRG withdrew its request that the Board determine an IR Plan in this phase of the proceeding.

160. To be clear, NRG has deferred consideration of its IR Plan to Phase 2 of this proceeding. NRG's five-year IR Plan evidence remains "live" before the Board.

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[17] OEB Transcript, Hearing Day 3, page 89, beginning at line 10.

[18] OEB Transcript, Hearing Day 3, page 9, lines 3 through 15.

161. As noted in Ms. McShane's evidence, 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.

162. There is nothing improper about the Board looking at historic and expected future equity levels in order to assist in the determination of an appropriate capital structure for a utility. Indeed, NRG submits that such a consideration is appropriate in the context of a multi-year incentive regulation application. There is no good reason for the Board to approach the determination of capital structure with blinders to the factors influencing debt:equity ratios of the utility in the recent past and IR term.

163. That is also the view of the only expert evidence on this point in this proceeding, and was also what the Board considered in NRG's last rate case (at pages 20 through 27). In its last rate case, the Board found that NRG's actual ratio could be used unless it is unreasonable. Part of the determination as to reasonability involves considering a variety of factors (such as, in NRG's case, the impact of IGPC's addition to NRG's rate base, and NRG's plan for a multi-year IR Plan). With this in mind, NRG submits that the applied for capital structure of 58:42 is appropriate.

164. This is, of course, further supported by Ms. McShane's expert opinion at lines 413 to 532 that NRG faces no less business risk than at the time of the EB-2005-0544 decision.

(c) <u>Capital Structure – "Actual" Equity in 2011</u>

165. At paragraphs 46 through 68 of the Town of Aylmer's argument, the Town attempts to arrive at NRG's "actual equity" via starting with NRG's 2007 Rate Decision, and then tracking through subsequent NRG financial statements to determine what NRG's actual equity should be in Test Year 2011. The argument is difficult to follow, but it appears that the Town is trying to state that NRG has over-earned in the past several years (see paragraph 84).

166. NRG believes that the Town's argument here suffers from the following flaws: (a) it appears to miss the point on when it is appropriate to use a hypothetical capital structure; (b) it confuses growth in retained earnings with over-earning; and (c) it fails to recognize the concept of just and reasonable rates.

167. NRG will try to address each of these conceptual flaws.

168. A hypothetical capital structure is used when a utility's actual capital structure is unreasonable. NRG's hypothetical capital structure does not reflect the retractable feature of NRG's Class C shares, and Kathy McShane has testified to the proposed common equity ratio.

169. A rate regulated firm can under-earn as compared to the allowed rate of return and increase retained earnings. NRG's Exh. F3/1/1 through F8/1/1 provide the computed deficiencies.

170. Just and reasonable rates recover the costs incurred to provide service on an ongoing basis and provide the utility with an opportunity to earn an appropriate return on its invested capital. If the company does not increase its retained earnings in a period when it was not paying dividends to the shareholders, then it would not be earning profits. This is an unacceptable outcome.

(d) <u>Overall Cost of Capital – "Risk" of NRG</u>

171. At pages 5 through 10 of its argument, the Town provides substantive factual evidence and argument around conditions that it alleges either: (a) demonstrates that any business risk of NRG was created by NRG itself; and (b) NRG's business risk has actually lessened due to the connection of IGPC as a major customer.

172. It is difficult for NRG to understand how the lengthy re-iteration of past proceedings (the motions of June 2007 and February 2008, and the Union Cessation of Service hearing) have any relevance to business risk for the purposes of determining cost of capital.

173. With respect to the addition of IGPC as a customer being a factor that decreases risk (i.e., a replacement for the lost tobacco agricultural load and Imperial Tobacco industrial load),

NRG begs to differ. Having a single large customer replace a several medium-sized (by comparison) customers does not, in NRG's view, lead to less risk. In addition, the ethanol industry is heavily subsidized by governments, and in NRG's view, prone to its own unique risks (e.g., government policy, corn prices, etc.).

174. Moreover, Ms. McShane had all of these factors within her knowledge when she prepared her opinion (see pages 14 to 20 of Ms. McShane's opinion). Essentially, the Town's submission debates NRG's risk factors. The fact is that Ms. McShane is the expert on risk as it relates to utility cost of capital, and she has considered all relevant factors.

(e) <u>Capital Structure – Comparable Utilities</u>

175. 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.

176. A number of parties in this proceeding indicate that the majority of the proxy group companies[19] have a capital structure based on a 40% equity component. NRG notes that if you focus on the ten individual companies in the proxy group (i.e., leaving aside the Ontario Electricity LDCs data), the average ROE is 41.6%. Moreover, the only utility of the ten with a rate base similar in size to NRG (Northland Utilities – NWT) has an ROE of 44%.

177. Consequently, NRG is of the view that the proxy group supports the capital structure applied for by NRG.

[19] See page 21 of McShane opinion, found at Exh. E2/1/1 (Table 4), updated to current levels by Ms. McShane at page 86 of the OEB Transcript, Day 3 (i.e., Pacific NE ROE is now 40% not 36%; Pacific Northern Gas-West ROE is now 45%, not 40%).

(f) ROE and Capital Structure – Strict Adherence to Board Policy

178. Board Staff and the intervenors all argue that at most NRG's capital structure and ROE should be the based on the Board's recent *Report on the Cost of Capital for Ontario's Regulated Utilities* (EB-2009-0084, December 11, 2009)("CoC Report"). This would mean a capital structure of 60:40 (debt:equity) instead of NRG's applied-for 58:42, and an ROE of 9.85%.

179. NRG's submissions on this point are straightforward, and was set out in NRG's Argument-in-Chief but not really addressed by intervenors. First, as noted at page 50 of the CoC Report, while the Board has established a standard capital structure of 60:40 (debt:equity) for electricity distributors, the deemed capital structure for gas utilities is to be "determined on a case-by-case basis". 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.

180. 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.

181. 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.

182. 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.

(g) Cost of Debt – Impact of Compensating Balance

183. Board Staff and intervenors make the argument that the compensating balance provides no benefit to ratepayers and results in increased debt costs that are borne by ratepayers. Their argument is that the appropriate cost of debt is derived by taking the loan interest rate and multiplying it by the actual debt less the compensating balance.

184. This would, of course, result in NRG being unable to recover its actual interest expense, which in NRG's view an unreasonable result.

185. The compensating balance is required to maintain the covenants in the utility's loan arrangements. It is not for the benefit of NRG's shareholders or ratepayers, although the ability to obtain company financing is for the benefit of both. Maintaining a good working relationship with its lender is also in the best interests of NRG and its ratepayers.

(h) Capital Structure – Splitting Out Ancillary Services

186. This issue was raised by the Town of Aylmer alone. The Town goes on at some length about the inclusion of the ancillary business within NRG. The Town essentially wants the ancillary services removed from the cost allocation exercise. Right now, the total assets of the utility include the regulated assets and the ancillary services (water heater rentals).

187. As part of the cost allocation exercise, the rate base, OM&A costs, depreciation, taxes, etc. are split between the regulated distribution business and the ancillary businesses, so the Town's request has already been met. The Town asserts that the rate base that should be used to determine the allowable return on capital should only be that related to the utility. That is already the case.

188. As long as the ancillary business earns the requested return it is not subsidized by the regulated part of the business, and the Board can impute revenues to the ancillary businesses to ensure there is no subsidization. This is the exercise the Board engages in at every NRG rate case.

189. There is, of course, a key assumption that underpins this allocation. This is that the ancillary business has the same capital structure as the regulated distribution business. Most stand alone ancillary businesses such as renting water heaters would have an actual capital structure that included more debt and less equity than a regulated utility (i.e. it is a riskier business). This has given rise to concerns by the Town that nobody really knows the actual amount of equity underpinning the regulated distribution business.

190. This is not a valid concern, in NRG's view, because the ancillary business is assumed to have the same capital structure underpinning it as does the regulated business for rate-setting purposes. The actual amount of equity on the balance sheet can be split between the regulated distribution business and the ancillary businesses based on the rate base amounts for both.

191. The Town appears to be pushing the Board to have separate accounting for the ancillary businesses but within the same company. The Board will recall that it required Union and Enbridge to split off their ancillary businesses into separate companies. It did not require the same of NRG, and NRG's ancillary business is scrutinized as part of every rate case. The existence of the ancillary business may be news to the Town, but it is well-known and settled for NRG and the Board.

192. For the separate accounting to be carried out, an allocation of common costs would need to be done, which is essentially what is already done in the cost allocation study. Consequently, the Town's request to completely segregate the assets, revenues and costs associated with its non-regulated ancillary business is of no value to anyone, and should be rejected.

193. The evidentiary basis for NRG's submission on this issue can be found at Sheet 3.1 at Exh. G3/2/1 (which shows the ancillary services component of rate base on line 21) and on Sheet 3.3 of the same schedule (which shows the allocation of the revenue deficiency to ancillary services at lines 17 to 20).

(i) <u>Profit from Ancillary Business</u>

194. At paragraphs 40 through 42 of the Town's argument, the Town suggests that NRG has stated in its evidence that its ancillary business is <u>not</u> profitable. The Town then suggests

that the ancillary services revenues shown on Undertaking J3.1 are "implausibly" high and in any event, after "deduction of losses", the ancillary business profits amount to only $93,927 on $1.7 million in ancillary-allocated assets.

195. NRG does not understand the calculation of the $93,927 amount, nor what "losses" the Town is referring to in their argument. Further, NRG has never, to its knowledge, suggested that its ancillary business is not profitable. In fact, the opposite has been true since 2006.

196. NRG believes that the Town is not reading Undertaking J3.1 correctly. The schedule shows that the ancillary services income after tax since 2006 has been around the $200,000 mark, which has been far more profitable than NRG's utility business. There is no deduction for losses to be made to those figures.

197. The Town's understanding of this Undertaking and the ancillary services issue is exactly the opposite of what is actually happening.

198. As noted in the section above, the Board always scrutinizes the rate of return of NRG's ancillary services business at NRG's rate hearings. As long as the ancillary business earns the requested return it is not subsidized by the regulated part of the business.

(j) <u>Level of Debt</u>

199. The Town of Aylmer on the one hand takes the view that NRG has too much debt, and on the other hand states that it is paying down its debt too quickly (set out at the top of page 24 of its argument).

200. The Town incorrectly states that NRG has repaid over $2 million in debt in the last three years comprised of half a million dollars in reduced working capital (related to security deposits), repayment of two related-company loans, and a $1.2 million repayment of long-term debt.

201. With respect to the security deposits, this was a gradual return of monies held as deposits (as a result of a relaxation in the security deposit policy terms and conditions).

202. With respect to the second item, NRG would like to clarify the nature of the loans. As noted in NRG's response to the Town's IR9, there were two loans. The first was a loan to NRG from an NRG-related company in the amount of $795,264 that NRG repaid in 2009. That loan to NRG was interest-free. Part of the funds used to pay off that loan was via an NRG-related company paying off a loan from NRG in the amount of $492,505. That loan had an interest rate of 4.59% payable monthly. NRG is not sure why the Town would complain about this arrangement. NRG's ratepayers enjoyed an interest-free loan from a related company while earning interest on another loan to a different related company.

203. NRG's debt costs are recouped in rates. NRG believes that it is appropriately and prudently paying down its debt load, which grew after the addition of the IGPC Pipeline. This would seem to be in the interests of the company and its ratepayers.

H. <u>COST ALLOCATION</u>

(a) <u>Introduction</u>

204. Board Staff, IGPC and VECC made minor submissions on cost allocation, which can briefly be summarized as follows:

- Board Staff seeks clarification on whether the business interruption insurance (which as Board Staff notes, has been fully allocated to IGPC) covers business interruption for the entire NRG distribution system or just interruption to the IGPC Pipeline. If the former, then Board Staff submits that the costs should be allocated to all NRG's ratepayers. If the latter, then Board Staff submits that the costs are appropriate allocated to IGPC.

- VECC accepts NRG's proposal with respect to the allocation of Administrative and General ("A&G") costs to Rate 6. VECC also supports NRG's allocation to IGPC of: (a) 22.5% of property insurance, equipment floater and fleet insurance; (b) 100% of additional umbrella liability insurance; (c) 100% of business interruption insurance; and (d) 100% of transfer station insurance. VECC does not accept NRG's proposal to allocate 40% of its general liability and umbrella liability coverage to IGPC, on the grounds that the Zurich Insurance letter is not sufficiently transparent.

- IGPC is not requesting the Board to order changes in the allocation of costs for the purposes of this proceeding. However, IGPC is asking the Board to direct NRG to prepare a new cost allocation study for its next cost of service rate application. IGPC's rationale for this recommendation is straightforward: (a) NRG's cost allocation study was developed almost 20 years ago; (b) NRG has added a new rate class (Rate 6) with a single customer that uses dedicated facilities; and (c) NRG is also in the midst of seeing its Rate 2 class (seasonal tobacco growers) disappear.

205. NRG's response to these submissions are set out below.

(b) <u>Response to Board Staff</u>

206. As noted in Undertaking J2.6, the business interruption insurance is related solely to IGPC. By this, NRG meant that it only covers interruptions to the IGPC Pipeline (and not NRG distribution system interruptions). That is the rationale for the 100% allocation of these insurance costs to IGPC.

(c) <u>Response to VECC</u>

207. NRG agrees with VECC that the Zurich letter is insufficient in that it provides little support or explanation for its conclusion (which is that an appropriate risk allocation is 40%). NRG's cost allocation model had initially allocated 64.5% of the general liability and umbrella liability insurance costs to IGPC. At the request of IGPC, NRG agreed to have an insurer provide an opinion on not only the appropriate amount of insurance to cover off the additional risk presented by the IGPC Pipeline, but also on the appropriate allocation of insurance to IGPC versus the rest of NRG's ratepayers (as an alternative to

using gas volume as an allocator). This proved to be a painful exercise, as Mr. Cowan noted under cross-examination.[20]

208. That having been said, as Mr. Todd pointed out, Zurich is the expert in risk (as compared to Elenchus or NRG) so the figure in the Zurich letter, despite being short on explanation, is the best figure we have to go on at the moment.[21]

I. CRITICISMS OF EVIDENCE

209. Both the Town and IGPC complain about the evidence provided by NRG in this proceeding. In fact, the criticisms of NRG are so severe (i.e., the evidence is so flawed, according to these two parties) that they suggest the Board has virtually no basis to ensure the rates it approves are just and reasonable.

210. This is the first time these concerns have been raised by these two parties. It could have (and if their concerns are to be believed, should have) raised these prior to or at the oral hearing. That would have been the proper thing to do. Instead, both parties chose to lie in the weeds and let fly with their criticisms only in intervenor reply argument.

211. Board Staff and VECC have raised no such issues with the evidentiary record. In NRG's view, that speaks volumes.

212. The criticisms about the evidentiary record in this proceeding are bogus, made in bad faith, and arguably for an improper purpose. They should be completely disregarded.

213. Somehow, according to IGPC and the Town, the combination of Elenchus Research Associates, Foster Associates and Ogilvy Renault (directed by a company controller that is a Chartered Accountant, formerly of Coopers & Lybrand, and a company co-chair with more than forty years of commercial law experience) could not pull together an

[20] OEB Transcript, Day 2, page 103, starting at line 17.

[21] OEB Transcript, Day 2, page 107, starting at line 20.

acceptable rate application and evidence – even when using a rate model that has been used by NRG, and been the basis for several previous NRG rate applications.

214. The complaints of IGPC and the Town are that there were material errors in the evidence that required evidentiary updates and corrections and that such errors undermine the legitimacy of the evidence. Further, IGPC suggests that these errors were intentional on the part of NRG, designed "solely to drive an increased revenue stream". IGPC states that "the effect of such inconsistencies, omissions and errors have been solely to the benefit of NRG and not ratepayers." This is a serious allegation because it clearly goes to the integrity of Mr. Cowan and Ms. O'Meara (NRG's witnesses), who adopted and affirmed as to the truthfulness of the company's evidence.

215. Neither the Town nor IGPC provide any examples of the errors in the arguments. The reason for this is simple. If they were to do so, there would be very little for them to rely upon.

216. The main evidentiary corrections made following the March filing were as follows:

(1) Rate Base: NRG corrected the treatment of asset retirements in the automobile and residential hot water heater categories, as a result of an information request from VECC (no material impact).

(2) Ancillary Services: NRG corrected the derivation of allocated costs to ancillary services to use consistent allocators. This came to light as a result of an information request which showed that the model was not calculating correctly. The impact of this was to the allocation of OM&A in the 2010 Bridge Year, so had no material impact.

(3) Cost of Service: NRG removed a double recognition of depreciation expense on ancillary services (hot water heaters) when computing the deficiency. This was an error that (if uncorrected) favoured ratepayers in the amount of $120,000 (to the detriment of NRG). When NRG discovered it (see Undertaking JT1.1, resulting from a VECC question at the beginning of the Technical Conference), it agreed to not take the full benefit of the error (see Continuity Schedule at Appendix A to the Settlement Agreement).

(4) Capital Cost Allowance: Removing the double recognition of CCA with respect to the IGPC Pipeline, which was transparent and found by NRG when preparing continuity schedules during the Settlement Conference.

(5) Cost of Service: The direct assignment of insurance expense to IGPC was an issue that was corrected during the oral hearing. The total amount of insurance was not an issue, only the allocation.

(6) IGPC Pipeline Economic Feasibility: NRG's legacy economic feasibility model was updated.

(7) IGPC Capital Cost: There were some very minor corrections made to the capital cost reconciliation, as a result of the detailed review of legal invoices, consulting time sheets, and Neal Pallet audit of emails (e.g., one double entry of Mr. Bristoll's time). The only material errors all related to NRG's calculation of interest, and NRG corrected these which resulted in the interest component of the capital cost to be reduced by $26,000 in the Settlement Agreement (see second bullet at top of page 9 of the Settlement Agreement), and then by a further amount of approximately $80,000 by way of Undertaking J1.5.

217. These were the amendments made following the March evidentiary filing. Collectively, they do not rise to any level of materiality.

218. In fact, NRG submits that given the ambitious nature of this filing, the number of corrections made were quite low. Keep in mind that the current rate application was highly unique for NRG, for the following reasons: (a) the rate model had to be modified to add a new rate class with a single large customer that had unique cost allocation issues associated with it; (b) it had been four years since NRG's last rate case so there was more historical information to be inputted to the model (including the data related to the construction of the IGPC Pipeline, a very significant project); (c) NRG for the first time filed a multi-year IR Plan; and (d) NRG had new management and new rate consultants that were not as familiar with the complexities of the rate model. In addition, unlike past rate applications, NRG was mandated to file an application and evidence by a specified deadline, instead of according to NRG's desired timing.

219. NRG has never had the legitimacy of its rate model and evidence, nor the integrity of its witnesses, ever called into question by the Board at a previous rate hearing. Neither Board Staff nor VECC did so at this proceeding. Only the Town and IGPC have raised these unfounded allegations in this proceeding. NRG can only conclude that they do so not because of any basis for their allegations but because: (a) they continue to bear ill feelings towards NRG as a result of IGPC's displeasure with the failure of NRG to sign contracts in the summer of 2007 and the Town's displeasure with NRG's former security deposit policy. Both are issues in the past and have no bearing on this rate case, but it is clear that bad feelings on the part of IGPC and the Town persist towards NRG. This has caused IGPC and the Town to continue to take an aggressive approach to its dealings with NRG, which ultimately has caused NRG to incur additional legal fees and other costs.

220. In addition, IGPC and the Town appear to be continuing a strategy of raising what NRG considers unfounded allegations and historical grievances to try to establish a foundation for their opposition to NRG's franchise renewal application next year. To that end, NRG notes that the Town states that these unfounded "evidentiary failures are not consistent with good utility practice", while IGPC states that "NRG's lack of transparency and lack of financial discipline … fails to meet the expected the (sic) standard of regulated public utility (sic)". NRG notes that not only are both IGPC and the Town the only two intervenors to raise these "fatal flaw" issues with NRG's evidence, but it is curious that both conclude their submissions on this point by asserting that these failings are essentially indicia of poor utility practice (a relevant consideration on franchise renewal).

221. Both IGPC and the Town may continue to have ill feelings toward NRG and both may wish to oppose NRG's next franchise renewal, but it seems clear to NRG that: (a) IGPC and the Town are throwing out unfounded allegations in an effort to "condition" the Board Panel for a future opposed franchise hearing; or at a minimum (b) IGPC and the Town are so coloured in their view when it comes to NRG, that it taints their perspective. If the former is the case, it is inappropriate and an affront to the Board. If it is the latter, the submissions of IGPC and the Town have to be viewed with this bias in mind.

All of which is respectfully submitted this 13th day of October, 2010.

NATURAL RESOURCE GAS LIMITED

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Per: Richard J. King