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Your reference

Our reference
01012724-0011

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Dear Ms. Walli:

Natural Resource Gas Limited ("NRG")
Responses to Information Requests (EB-2010-0018)

We are counsel to NRG. Enclosed please find NRG's responses to Information Requests from Board Staff, the the Integrated Grain Processors Cooperative ("IGPC") and the Vulnerable Energy Consumers Coalition ("VECC"). An electronic copy has been filed with the Board via the RESS system.

Yours very truly,

"Signed"

John Beauchamp

JB/mnm

Enclosures

Cop(y/ies) to: All intervenors and interested parties

NATURAL RESOURCE GAS LIMITED

RESPONSES TO INTERROGATORIES FROM BOARD STAFF

Note that responses to questions regarding the system integrity report were supplied in consultation with Aecon Utility Engineering

INTERROGATORY #1

Ref: Exhibit H1, Tab 1, Schedule 2 – Revised April 2011

1. NRG has proposed an incentive regulation ("IR") plan that is based on the Board's multi-year electricity rate distribution plan. NRG is proposing a three year IR plan starting with the fiscal year 2012. Please provide the proposed capital expenditures for the fiscal years 2012, 2013 and 2014.

RESPONSE

NRG estimates that its capital expenditures will total between $700,000 and $1-million for each of the fiscal years of 2012, 2013 and 2014.

INTERROGATORY #2

Ref: Exhibit H1, Tab 1, Schedule 2 – Revised April 2011

2. Please provide the depreciation amounts by rate class currently included in rates.

RESPONSE

		Depreciation By Rate Class ($000's)
Rate Group 1	Residential	$ 539.31
Rate Group 1	Commercial	$ 67.01
Rate Group 1	Industrial	$ 19.51
Rate Group 2		$ 42.24
Rate Group 3		$ 25.82
Rate Group 4		$ 16.15
Rate Group 5		$ 14.36
Rate Group 6		$ 243.60
		$ 968.00
Ancillary		$ 206.10
Total Depreciation		$ 1,174.10

INTERROGATORY #3

Ref: NRG System Integrity Study dated July 15, 2011

3. The System Integrity Study has proposed three alternatives to address the supply of gas in NRG's southern service areas. Did Aecon Utility Engineering consider the possibility of sourcing gas from the IGPC pipeline? Also, please provide the additional cost of building the IGPC pipeline if NRG had installed a larger pipeline for IGPC that would have served IGPC and brought additional supplies for serving NRG's southern service area.

RESPONSE

The NPS-6 pipeline is a 28.5km long steel pipeline dedicated to feeding the IGPC plant. This pipeline was only designed to handle the IGPC gas load at a delivery pressure of 420kPag – not to supplement the Town of Aylmer (it was never meant to be part of NRG's distribution network). Consequently, the notion of providing reinforcement to the NRG distribution network has been deemed unfeasible and never considered in the study (no cost estimates can be provided). Our preliminary assessments is that even if this were an option, it would not solve the problem.

INTERROGATORY #4

Ref: NRG System Integrity Study dated July 15, 2011

4. Please provide the approximate financing that NRG would need if it were to implement alternative one or two identified in the System Integrity Study. Would it be possible for NRG to raise the required capital to implement the project? Please provide a detailed response.

RESPONSE

Construction of the major pipeline identified in alternative one and two from the System Integrity Study would incur substantial costs over and above those direct costs detailed in the study. Additional costs would include expenses relating to, among others: financing; surveying; project management; environmental inspection and testing; and the costs of securing land and right of ways. These costs would likely add an additional 25 to 35 percent to the total cost of the pipeline proposed in the System Integrity Study.

NRG cannot issue bonds to the public market or secure term bank financing. Note that when financing the original IGPC pipeline, the IGPC letter of credit was not given consideration by the bank (the IGPC letter of credit can be called by the bank only if IGPC is in default) and NRG's shareholders were required to invest an additional $3,000,000 in capital as a condition of the bank granting the loan. Thus, customer charge rates would have to be pre-determined before any application for project financing is submitted to the bank. This revenue would help support the loan (allowing NRG to maintain its financial integrity with the bank). Shareholders may also be required to invest additional capital as required by the bank.

It should be noted that the pipeline, as described in the System Integrity Study, would not service any new customers and present customers would experience significant rate increases as required to service the additional financing and capital requirements.

INTERROGATORY #5

Ref: NRG System Integrity Study dated July 15, 2011

5. What would be the approximate rate impact on the different rate classes if NRG were to implement one of the first two alternatives identified in the study?

RESPONSE

As noted above in the answer to Board Staff IR #4, a number of expenses are not quantified in the System Integrity Study. Consequently, we have increased the costs for each alternative by 25% when determining the approximate rate impact on the different rate classes. It should be noted that NRG expects costs could increase by as much as 35%.

Alternative One – approximate rate impact would be overall 22.2%

Alternative 1 - Delivery Bill Impact By Rate Class (with 25% increase in costs)

		Current Revenue Requirement	Alternative 1 By Rate Class	Adjusted Revenue Requirement	Delivery Bill Impact
Rate Group 1		$ 3,696,116	$ 1,014,018	$ 4,710,134	27.4%
Rate Group 2		$ 69,292	$ 37,654	$ 106,946	54.3%
Rate Group 3		$ 164,530	$ 107,546	$ 272,075	65.4%
Rate Group 4		$ 62,189	$ 26,213	$ 88,402	42.2%
Rate Group 5		$ 74,448	$ 47,268	$ 121,716	63.5%
Rate Group 6		$ 1,484,464	$ -	$ 1,484,464	0.0%
		$ 5,551,038	$ 1,232,698.50	$ 6,783,736.82	22.2%

Alternative Two – approximate rate impact would be overall 23.8%

Alternative 2 - Delivery Bill Impact By Rate Class (with 25% increase in costs)

		Current Revenue Requirement	Alternative 1 By Rate Class	Adjusted Revenue Requirement	Delivery Bill Impact
Rate Group 1		$ 3,696,116	$ 1,086,929	$ 4,783,045	29.4%
Rate Group 2		$ 69,292	$ 39,710	$ 109,002	57.3%
Rate Group 3		$ 164,530	$ 116,521	$ 281,051	70.8%
Rate Group 4		$ 62,189	$ 28,070	$ 90,259	45.1%
Rate Group 5		$ 74,448	$ 51,140	$ 125,588	68.7%
Rate Group 6		$ 1,484,464	$ -	$ 1,484,464	0.0%
		$ 5,551,038	$ 1,322,370	$6,873,409	23.8%

INTERROGATORY #6

Ref: NRG System Integrity Study dated July 15, 2011

6. Please provide the annual excess amount paid by ratepayers for gas purchased from the affiliate at the rate determined by the Board in its Decision of December 6, 2010 as compared to the current QRAM rate approved by the Board.

RESPONSE

NRG does not have a full year's worth of data at this point and so cannot provide the "annual excess amount paid". We believe the best method at this point would be to use the Board-approved volume and current QRAM rate. Under this formula the excess amount paid is:

Board-approved volume of 2.4m x current QRAM = $88,282

Note – that this will be offset by approximately 10% for savings in transportation costs.

INTERROGATORY #7

Ref: NRG System Integrity Study dated July 15, 2011

7. Please provide the estimated annual maintenance costs of the 4 inch high pressure steel pipeline if NRG were to implement alternative one or two as identified in the System Integrity Study.

RESPONSE

As a high-level cost estimate, it is recommended that the annual maintenance cost for the NPS-6 IGPC pipeline be used for the NPS-4 pipelines described in this study and prorated based on length of pipe.

INTERROGATORY #8

Ref: Maintenance Protocol for IGPC Pipeline – Filing of April 28, 2011

8. The evidence indicates that NRG issued a Request for Proposal ("RFP") to develop a maintenance protocol for the IGPC pipeline. In the document on page 2, NRG has provided a list of potential elements of the maintenance protocol. Please answer the following:

a) Why did NRG provide a potential list when it was expected that independent experts who had experience in building and managing pipelines would be responding to the RFP?

RESPONSE

In the RFP, NRG clearly stated that the maintenance protocol should "ensure compliance with all legal/regulatory standards in Ontario, be commensurate with good utility practice, and be consistent with the industry standard for maintenance of similar facilities in Ontario". NRG did not provide a prescriptive list of elements for the maintenance protocol – rather, "potential elements" were provided (simply because NRG thought they may be of use to applicants when drafting proposals).

INTERROGATORY #9

Ref: Maintenance Protocol for IGPC Pipeline – Filing of April 28, 2011

9. Please provide the actual maintenance costs of the IGPC pipeline to-date for the years 2010 and 2011. Please provide a breakdown of the costs based on the potential elements identified in the maintenance protocol RFP.

RESPONSE

Please refer to the answer provided under IGPC IR #1.

INTERROGATORY #10

Ref: Maintenance Protocol for IGPC Pipeline – Filing of April 28, 2011

10. If possible, please provide annual maintenance costs of a similar independently managed pipeline within North American.

<u>RESPONSE</u>

We do not have this information. We also asked Aecon Utility Engineering and they do not have this information either.

INTERROGATORY #11

Ref: Maintenance Protocol for IGPC Pipeline – Filing of April 28, 2011

11. As a business decision, what approach would NRG prefer to follow with respect to maintenance of the IGPC pipeline? Please provide reasons for the decision.

RESPONSE

As a utility, NRG must ensure that the IGPC pipeline is operated and maintained in a manner that complies with all legal standards, be commensurate with good utility practice, and be consistent with the industry standard for maintenance of similar facilities in Ontario. NRG believes the original maintenance proposal from MIG Engineering filed in evidence accomplishes these goals. The annual maintenance cost of the MIG proposal amounted to 1.3% of the total cost of the pipeline prior to the aid to construct and 2.3% of the cost of the pipeline after the aid to construct. NRG believes this is a reasonable proposal.

NATURAL RESOURCE GAS LIMITED

RESPONSES TO INTERROGATORIES FROM
INTERROGATORIES OF THE VULNERABLE ENERGY CONSUMERS COALITION.

Note that responses to questions regarding the system integrity report were supplied in consultation with Aecon Utility Engineering.

INTERROGATORY #1

1. Please provide a comprehensive table that shows all of the similarities and differences between each element of the Board's 3rd Generation IRM and NRG's revised IR plan proposal.

RESPONSE

Elements of the IRM Plan	Board's 3rd Generation IRM	NRG's revised IR plan
Application of GDP-IPI Price Cap Adjustment	GDP-IPI 1.3% less Productivity less 0.72% less Stretch Factor	Same
Incremental Capital	Threshold Calculation	Same – Not Applied For
Z-Factor	Three Eligibity Criteria Test Materiality Need Prudence	Same – Not Applied For
50/50 Shared Tax Savings	50/50 Shared	Same
Rate Adders / Rate Riders	As necessary	As necessary
EDDVAR Group 1Deferral Account disposition	Threshold Test	Not Applicable
RTSR Rate Adjustment	As Necessary	Not Applicable
Revenue-to-cost Ratio Adjustment	As ordered by the Board	Not Applicable

INTERROGATORY #2

2. Please provide a comprehensive table that shows all of the similarities and differences between each element of the IR plan initially filed by NRG and NRG's revised IR plan proposal.

RESPONSE

Parameters	Initial IR Plan	Revised IR Plan
Annual adjustment mechanism	Union Gas price cap index with fixed annual escalator (to be defined)	Price-cap adjustment using GDP-IPI less 0.72% productivity less stretch factor.
Rebasing	Rebasing required before implementation	SAME
Earnings-Sharing Mechanism (ESM)	50/50 ESM over 200 basis points	No ESM
Term of the Plan	Five years with two year extension	Three years IRM
Off-Ramps	±300 Basis points on weather normalized earnings	Annual ROE dead band of ±300 basis points
Z-factors	Cost Causality Prudence Materiality ($50,000)	SAME
Y-Factors (deferral/Variance accounts)	• Upstream gas costs • Upstream transportation and storage.	SAME
Service quality monitoring	As required in annual OEB RRR filings	SAME
Financial Reporting	As required in annual OEB RRR filings	SAME
Alternative Dispute Resolutions	Only if required	SAME

INTERROGATORY #3

3. Please provide any updates with respect to the parameters associated with the revised proposal.

RESPONSE

NRG has applied the Board's most recent parameters as issued March 2, 2011. No further updates have been provided by the Board.

INTERROGATORY #4

4. Given that there is an expectation that there will be savings during the IR plan term with respect to the debt component of the cost of capital as existing debt instruments are refinanced, please explain why these savings should be treated differently than tax savings under 3G IRM, i.e., 50:50 sharing between the ratepayer and the shareholder.

RESPONSE

Application of the GDP-IPI component is intended to adjust for the current changes in economic conditions from the date of the last cost of service application. Changes to the market debt rate component of cost of capital or equity component in 3G IRM are presumed to be captured in the GDP-IPI. NRG's proposal is to replicate 3G IRM in all respects, including treatment of changes in debt cost.

INTERROGATORY #5

5. At current rates, does NRG project a revenue sufficiency for 2012? For 2013?

RESPONSE

NRG does not project a revenue sufficiency for 2012 and it is too early to make projections for 2013.

INTERROGATORY #6

6. Would NRG be prepared to accept any type of earnings sharing mechanism over the term of its IR plan? Please explain fully.

RESPONSE

NRG has proposed using the electricity distributors IRM model as a base for its IRM process. The underpinning reason for proposing to use this model is that NRG is more closely aligned with smaller Ontario electricity distributors with respect to size of territory, size of customer base and the nature of risk. NRG has also chosen this model for its simplicity of application. The electricity distributors IRM model is a price-cap adjusted economic model, not a revenue-cap adjusted economic model. The electricity distributors IRM model focuses more on productivity or cost efficiency sharing by including the productivity factor and stretch factor. On page 42 of the July 14, 2008 *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, the Board reasoned that an earning-sharing mechanism should not be considered in the electricity distributors IRM model. The electricity distributors IRM compensates for this by incorporating an off-ramp test which would allow the Board to perform a regulatory review.

INTERROGATORY #7

7. Has NRG identified any specific areas in which it would be incented to find sustainable cost reductions over the IR plan period and beyond? If so, please identify these areas and quantify the projected savings where possible.

RESPONSE

NRG is a small utility with very few staff. We do not believe there are any unexplored areas that could provide additional cost reductions.

INTERROGATORY #8

8. Please provide a list of all the Z-factors that NRG is proposing in this phase of the proceeding.

RESPONSE

As per Chapter 3 of the OEB Filing Requirements, Z-factors are intended to provide for unforeseen events outside of a distributor's management control. The cost to a distributor must be material and its causation clear. NRG would intend to exercise Z-Factor claims should such an event occur. Examples of Z-factors that NRG may apply for might be:

- Storm Cost Recoveries
- Decommissioning Cost
- Loss of significant customer load or revenue.

INTERROGATORY #9

9. Please provide an exhaustive list of the approvals sought by NRG in this phase of the proceeding.

RESPONSE

NRG seeks the following approvals at this stage of the proceeding:

- approval of its revised incentive regulation plan, filed with the Board on May 6, 2011;
- approval of the IGPC pipeline maintenance cost estimates identified in the proposal submitted by MIG Engineering (see NRG's initial rate application, filed April 1, 2010); and
- approval of NRG's proposal to purchase integrity gas from NRG Corp. at the current rate.

INTERROGATORY #10

10. When and under what regulatory process does NRG propose to deal with service quality monitoring?

RESPONSE

NRG abides by the same service quality monitoring and reporting requirements that all gas distributors in Ontario are expected to address. In 2010, an audit was performed on NRG's performance with respect to service quality requirements. By letter dated September 3, 2010, Regulatory Audit and Accounting of the Ontario Energy Board identified seven outstanding issues related to the follow-up items and implementation of action plans by NRG. As can be seen in the attached correspondence, Regulatory Audit and Accounting recently performed a follow-up review of NRG's SQR audit to ensure that the audit findings in the September 3, 2010 SQR audit review report were properly addressed and that the required action plans were implemented. This review found no issues related to the follow-up items and implementation action plans. The Board further acknowledged the effort and time invested from NRG staff with regard to SQRs, including data collection, validation process, calculation and measurement, and regulatory reporting to the Board.

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Ontario

March 29, 2011

Mr. Jack Howley
General Manager
Natural Resource Gas Limited
39 Beech St. E.
Aylmer ON, N5H 2S1

Dear Mr. Howley,

Re: Follow up Audit Review of Service Quality Requirements (SQRs)

By letter dated September 3, 2010, Regulatory Audit and Accounting ("Regulatory Audit") of the Ontario Energy Board (the "Board") identified the following seven outstanding issues related to the follow-up items and implementation of action plans by Natural Resource Gas Ltd. ("NRG"):

1. To address Finding #1 of the Audit Review findings, NRG should conduct independent random audits for the purpose of verifying billing accuracy on a monthly basis. NRG has planned to conduct ten (10) per month random audits. Billing audit verifications are to be recorded on a monthly basis. NRG should commence with on its September 2010 billing cycle. NRG has committed to a plan to implement Finding #1 on September 30, 2010.
2. To address Finding #3 of the Audit Review findings, NRG under the Measurement for 'Appointments Met Within the Designated Time Period' should exclude re-connections due to non-payment. NRG should correct the measurement and follow Section 7.3.4.1 of Gas Distribution Access Rule (GDAR). NRG has committed to a plan to correct this measurement as of September 30, 2010. This correction should be reflected for the reporting period from November 1, 2009 to September 30, 2010.
3. To address Finding #4 of the Audit Review findings, NRG should include all types of appointments including missed appointments in the calculation of 'Appointments Met Within the Designated Time Period'. NRG should correct this measurement for the reporting period of November 1, 2009 to September 30, 2010. NRG committed to a plan to correct this measurement as of September 30, 2010.

4. To address Finding # 6 of the Audit Review findings, NRG should implement a procedure for the gas technicians to record and document all procedures carried out in response to a specific emergency category. NRG's Emergency Co-ordinator should audit every emergency call to ensure that established procedures are strictly adhered to. NRG committed to implement this on September 30, 2010.
5. To address Finding # 7 of the Audit Review findings, NRG should develop a retention policy and should monitor its implementation on an ongoing basis. NRG committed to a plan to establish a Policy on October 31, 2010.
6. To address Finding # 8 of the Audit Review findings, NRG should ensure that all emergency repair records are validated and signed and that a second person has been nominated to validate these repairs in the absence of the Primary Emergency Co-ordinator. NRG committed to implement this on September 30, 2010.
7. To address Finding #10 of the Audit Review findings, NRG has recently purchased a new IP telephone system. NRG has identified that this system has the capability to capture the required data which should allow NRG to report the measurements as required under Sections 7.3.1.1 and Sub-section 7.3.1.2 of GDAR. NRG committed to a plan to implement Finding #10 on October 31, 2010. NRG anticipates that within thirty (30) days of implementation, this system should be in place and that it can then record the data from October 1, 2010 onwards.

Regulatory Audit conducted a recent follow-up review of the outstanding items listed above of NRG's SQR audit to ensure that the audit findings in the September 3, 2010 SQR audit review report have been properly addressed and that the required action plans have been implemented.

This review has found no issues related to the follow-up items and implementation of action plans by NRG related to the findings of the audit review and its conformity to GDAR.

The findings and observations in this follow-up review represent the views of Regulatory Audit and are not necessarily the views of the Board as a whole.

The results of this review will be reported to the Board and may also be used as evidence in future proceedings involving NRG.

We would like to take this opportunity and acknowledge the effort and time invested from NRG staff with regard to SQRs, including data collection, validation process, calculation and measurement, and regulatory reporting to the Board.

We wish to thank the NRG staff for the assistance and support provided us during this review.

Yours truly,

D. Babaie

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Cc: Mr. .Anthony G. Graat Jr. - President

INTERROGATORY #11

11. Please provide full details of the financial reporting that NRG is proposing over the term of its proposed IR plan.

RESPONSE

NRG proposes to maintain its current financial reporting requirements in accordance with OEB RRR filing requirements.

INTERROGATORY #12

Ref.: Section 2.4

12.

a) The study states that NRG Corp has 40 wells in the area that can feed sales quality gas into NRG's distribution system. Are there any non-related gas producers in the area that can feed sales quality gas into NRG's system? If so, please identify all such producers and explain why NRG has not explored the alternative of buying system integrity gas from these producers.

b) Has NRG ever purchased gas from an unrelated gas producer either in its service area or able to supply gas to NRG's distribution system? If so, please provide full details along with the reasons that NRG no longer receives gas from such producers.

RESPONSE

a) and b) It has been several years since NRG purchased gas from an unrelated gas producer. The non-related gas producers in NRG's area are unable to guarantee production on a consistent basis. NRG must maintain a consistent flow of gas into its system to meet customer demand and, therefore, it was not considered in NRG's customers' best interest to rely on these companies.

INTERROGATORY #13

Ref.: Section 3.4, Model Runs of Existing Distribution System

13

a) Does the -28 degree day mentioned refer to a temperature of -10 degrees C or -28 degrees C?

b) Is the -28 degree C referenced in part a) consistent with the "-28 C Day" at the top of the pressure map in Appendix 4?

c) Please explain how the choice of a –28 degree day was made for the model run for January 23/24, 2011.

d) Please identify which grain dryers were on for the simulation and the rate classes to which they belonged.

e) Were any of the grain dryers that were on for the simulation interruptible customers? If so, please identify which were interruptible and explain why interruptible loads were being served on a design peak day.

f) If applicable, please re-run the simulation with gas wells shut in and all interruptible customers cut off.

RESPONSE

a) The "-28 degree day" refers to the lowest temperature of minus 28 degrees Celsius recorded by Environment Canada for the general vicinity of the NRG distribution system.

b) Yes, the -28 degree Celsius referenced above in part (a) above is consistent with the "-28 degree day" at the top of the pressure maps in Appendix 4.

c) It was anticipated that January 23 & 24 of 2011 could be the coldest days for that winter. As such, we believed it would be a good opportunity to monitor system pressures and performance so that collected data may be used for further analysis.

d) All of the grain dryers were on for the simulation as we were determining the worst case scenario.

e) Yes some were interruptible. As mentioned above, we were determining the worst case scenario, where the goal is to maintain service to all customers without having to interrupt service. Interruption should be reserved for an unusual occurrence and for a short-term period.

f) We repeated the simulation with the interruptible grain dryers and wells off. While there was some improvement, we still did not have acceptable pressures in the problem areas.

INTERROGATORY #14

Ref.: Section 5, Proposed Alternatives

14.

a) Has NRG asked Union whether Union could supply more gas at a higher pressure at any or all connection points to existing Union stations? If not, why not?

b) Has NRG discussed the possibility with Union of increased capacity at any exiting or new stations? If not, why not?

c) Has NRG considered putting in its own compressors to increase pressure? If not, why not?

RESPONSE

a) The increase to Union Gas volume input would not solve the problem because of the distribution system limitations. It should be noted that we are currently running at the safest pressure our system will allow.

b) Refer to VECC IR #14(a) above.

c) The operating and maintenance cost of a gas compressor is deemed to be cost prohibitive for the intended application. Due to pressure and capacity limitations of the distribution gas main systems, the idea of introducing a compressor into the system was not considered.

INTERROGATORY #15

Ref.: Ibid and Appendix 1 – NRG System Map

15.

a) From the system map, it appears that there would be the possibility of getting more gas into the IGPC pipeline and connecting the IGPC pipeline to another point or points on NRG's existing distribution system to alleviate the system integrity concerns. Did NRG consider or pursue this option with Union? If so, what was the outcome? If not, why not?

b) Did NRG consider or pursue the possibility with Union of putting a new Union station in New Sarum and connecting it to NRG's system? If so, what was the outcome? If not, why not?

c) Did NRG consider or pursue the possibility with Union of connecting the Union pipeline that runs to Mapleton with the nearby red pipeline on NRG's system on the map? If so, what was the outcome? If not, why not?

d) The black pipeline out of the Putnam Station appears to be NRG's largest pipeline except for the IGPC pipeline. VECC understands that this pipeline, which ends near the IGPC pipeline, was used to serve Imperial Tobacco. Please confirm. If unable to so confirm, please explain fully.

e) If the premise in previous part d) was confirmed, please indicate where the capacity of the 6" pipeline goes now that Imperial Tobacco is no longer a customer.

f) If the premise in previous part d) was confirmed, please indicate whether in simulations the 6" pipeline is run at full capacity.

g) Please provide the Imperial Tobacco's firm demand in the last four years that it was receiving service from NRG.

h) Did NRG consider any alternatives with respect to connecting the pipeline referred to in part d) above?

i) Has NRG asked Union if any excess capacity is available now that Imperial Tobacco is gone?

j) Did NRG consider the option of connecting Port Bruce to Union's facility at Port Stanley? If not, why not?

RESPONSE

a) Please refer to answer provided under OEB IR #3.

b) Although Union Gas Limited was never approached to provide a cost estimate to run a new high pressure pipeline and erect a pressure regulating and metering station in the New Sarum area (just west of the Town of Aylmer), this option was deemed cost-prohibitive and one that would only benefit a small area of the NRG distribution network. Additionally, the distribution mains would have to be upgraded to achieve the same desired results as the options proposed in the study.

c) The reasoning given above under VECC IR #15(b) applies here as well.

d) The black pipeline coming out of the Putnam Station was used to serve the Imperial Tobacco plant. This pipeline is currently part of the distribution system simulation model.

e) The capacity of the NPS-6 line that served Imperial Tobacco is solely utilized by the neighbouring vicinity. It is being used as efficiently as possible given the existing interconnecting distribution system.

f) Yes – the NPS-6 line was feeding under full capacity during the cold-day model simulation runs.

g) Not applicable based on the answers given above.

h) No – NRG did not consider any alternatives with respect to connecting the pipeline described above under VECC IR #15(d), given that it is being fully utilized in our simulation and already forms part of the distribution system.

i) No – the "excess" capacity of the NPS-6 line that once fed the Imperial Tobacco plant cannot be effectively utilized by other customers due to existing gas mains in the area.

j) No – the option of connecting Port Bruce to the Union Gas facility at Port Stanley was not considered due to the high capital cost associated with this option.

INTERROGATORY #16

Ref.: Ibid and Appendix 4 - NRG System Pressure Map for Existing Simulation Model (-28C Day)

16.

a) The pipelines are colour coded by pressure on this diagram. The east side is mainly purple (highest pressure) especially in the south. Please explain why some of this highest pressure could not be moved from the purple pipelines to the blue pipelines, increasing the pressure at Aylmer by extending the purple pipelines to connect with the blue pipeline on the east side of Aylmer.

b) Please provide a list of all options to mitigate system integrity concerns that were considered by NRG but either not pursued or rejected. In each case please explain fully why the option was either not pursued or rejected.

Purchased System Integrity Gas from Related Company, NRG Corp.

RESPONSE

a) The option of upsizing existing gas mains to move more distribution pressure gas toward Aylmer was looked into but never considered as one of the viable alternatives for the following reasons:

- the total length of gas mains to be upsized may be as long as 20 kilometres;
- the upgraded distribution mains may be as large as NPS-20" which increases materials and construction costs significantly; and
- additional upgrading of existing sources of Union gas supply may have to be performed which will add to the overall cost.

b) In addition to the options discussed above under VECC IR #16(a), the following were considered but not pursued:

- Boosting outlet pressures and capacities at strategic Union Gas interconnecting stations without a new pipeline (this option would not work due to the fact that existing feeder gas mains are at capacity).
- Bringing a new pipeline from the west to feed the Town of Aylmer (this option would not work as there are no existing viable interconnecting stations or H.P. pipelines west of Aylmer).

While many options were discussed at length, there are no documented minutes to these discussions (NRG cannot provide a list of every option discussed). It is important to remember that the main issue is not simply volume-related, but rather the distribution system as a whole and the size of the existing lines.

INTERROGATORY #17

17. Please provide a full justification for the premium price that NRG proposes to pay NRG Corp for system integrity gas.

RESPONSE

This issue was fully canvassed in phase I of the rate proceeding – it was addressed in evidence, interrogatory responses, and during oral argument. As such, the justification for the price proposed for system integrity gas is part of the record of the proceeding and need not be reiterated here.

INTERROGATORY #18

18. Please confirm that system integrity problems occur in the winter and not in the summer.

RESPONSE

While this would normally be the case, system integrity issues can arise whenever there is an unusual strain placed on the system due to high demand. Thus, system integrity issues might occur in the winter (due to weather-related events) or in the summer (due to customer-related demand).

INTERROGATORY #19

19. Please confirm that if system integrity costs are recovered through the PGVA then Direct Purchase customers would not pay any system integrity costs.

RESPONSE

System integrity costs would be recovered through distribution rates, not commodity cost/PGVA; hence, direct purchase customers would pay.

INTERROGATORY #20

20. Please confirm that if system integrity costs are recovered through distribution rates then Direct Purchase customers would pay any system integrity costs.

RESPONSE

See response to VECC IR #19 above

INTERROGATORY #21

21. Are the energy contracts that NRG holds with NRG Corp firm contracts, i.e., does NRG Corp have to produce at a certain level?

RESPONSE

The contracts provide a firm price (fixed on an annual basis), but the quantity of gas required is determined by Natural Resource Gas Limited.

NATURAL RESOURCE GAS LIMITED

RESPONSES TO INTERROGATORIES FROM INTEGRATED GRAIN PROCESSORS CO-OPERATIVE INC.

INTERROGATORY #1

Ref: Undertaking JT1.6

Preamble: Phase II of the IRM includes IGPC Pipeline Maintenance Costs. In its Application, NRG requested approval of certain costs for the maintenance. The IGPC Pipeline has now been in operation for three complete years. As such, there should be a historical pattern of spending on the activities referenced in the MIG Proposal (Undertaking JT1.6).1.3 Are NRG's audited financial statements from 2006 to 2009 appropriate?

1. Please complete the following table providing the actual costs incurred for each line of the table.

Item	Undertaking JT1.6	Actual 2008	Actual 2009	Actual 2010	Actual 2011 Year to Date
Valve Maintenance	$1,500				
Pipeline Marker Maintenance	$950				
Leakage Survey	$1,187				
Odour Level Testing	$2,850				
Cathodic Protection Surv.	$1,295				
Anode Replacement	$840				
Pipeline Locates	$2,254				
Weekly Observations	$12,350				
3rd Party Observations	$4,680				
Ground Maintenance	$1,960				
Manual Review	$4,250				
Technician Training	$1,650				
Community Awareness	$8,500				
Make Pipeline Piggable (1 time expense)	$102,000				
In-Line Inspection ($70,200/10 years to annualize)	$7,020				

Item	Undertaking JT1.6	Actual 2008	Actual 2009	Actual 2010	Actual 2011 Year to Date
Emergency Response (Mock Emergency)	$18,000				
Engineering Design	$19,500				
Administration	$38,693				
Disbursements	$8,729				
Total Annual Cost					

RESPONSE

In an effort to provide accurate costs, NRG has attempted to incorporate its internal expenses to date. These numbers are based on internal hours multiplied by NRG's charge-out rate of $60/hour for services, plus 3rd party costs.

Item	Undertaking JT1.6	Actual 2008	Actual 2009	Actual 2010	Actual 2011 Year to Date
Valve Maintenance	$1,500		$1,500	$1,500	$900
Pipeline Marker Maintenance	$950		$880	$1,200	$700
Leakage Survey	$1,187		$1,187	$960.50	In progress
Odour Level Testing[1]	$2,850				
Cathodic Protection Surv.[2]	$1,295				
Anode Replacement[3]	$840				
Pipeline Locates	$2,254		$2,300	$2,500	$600
Weekly Observations	$12,350		$12,300	$12,300	$8,120
3rd Party Observations	$4,680		$4,680	$4,200	$600
Ground Maintenance	$1,960		$1,960	$1,960	$900
Manual Review	$4,250				$4,250
Technician Training	$1,650		$960	$960	$960
Community Awareness[4]	$8,500				
Make Pipeline Piggable[5] (1 time expense)	$102,000				
In-Line Inspection ($70,200/10 years to annualize)	$7,020				
Emergency Response[6]	$18,000				

Item	Undertaking JT1.6	Actual 2008	Actual 2009	Actual 2010	Actual 2011 Year to Date
(Mock Emergency)					
Engineering Design[7]	$19,500				
Administration[8]	$38,693				
Disbursements[9]	$8,729				
Total Annual Cost					

NOTES:

1 - MIG preparing bid document.

2 – MIG preparing bid document.

3 – Cost of one (1) anode. Replacement not yet required.

4 – MIG to schedule.

5 – Cost annualized.

6 – MIG to schedule in 2012.

7 – Not yet incurred.

8 – Total of administration costs in MIG invoice (a function of invoices charged).

9 – Total disbursements included in MIG invoice (a function of invoices charged).

INTERROGATORY #2

Ref: NRG Filing, dated April 28, 2011.

Preamble: Phase II of the IRM includes IGPC Pipeline Maintenance Costs. In a letter dated April 28, 2011, NRG filed proposals from two potential companies to develop a maintenance program.

i) Who provided the drafted proposed scope of the maintenance activities that is included in section 3.0 of the NRG Request for Proposals?

ii) Why were the maintenance companies not required to provide a proposed scope of maintenance activities?

iii) Does NRG have any industry studies or evidence regarding the average cost per kilometre for maintenance of new NPS 6 steel pipelines? If so, please provide any such studies.

RESPONSE

i) NRG prepared the drafted proposed scope of maintenance activities.

ii) In its Decision and Order (dated December 6, 2010), the Board ordered NRG to tender the maintenance of the pipeline and provide written bids to the Board. Specifically, the Board directed NRG to first retain by way of tender the services of an independent expert in the development of maintenance programs for pipelines similar to that employed in the supply of gas to IGPC. Following the development of a maintenance protocol NRG was then directed to retain the services of an enterprise experienced in the provision of such services by way of tender predicated on the maintenance protocol.

NRG's Request for Proposals followed this direction from the Board – experts were required to develop a maintenance protocol.

iii) No.

INTERROGATORY #3

Ref.: Exhibit H1, Tab 1, Schedule 2, April 2011, page 3 (off-ramp)

Preamble: Phase II of the IRM includes a proposed increase to the annual approved rates. A significant portion of the Rate 6 is associated with the cost of capital deployed. The evidence indicates the rate base allocated to Rate 6 will be declining. IGPC understands that IRM plans generally do not assume a declining rate base.

Also, the IRM proposes a specific off-ramp of +/-300 basis points and the parties would have an interest in ensuring that the off-ramp is not triggered unnecessarily. NRG was renegotiating its capital financing with the Bank of Nova Scotia.

i) Please complete the following table.

Year	Rate 6 Rate Base	Decrease In Rate Base Against Prior Year
2011 Test Year		
2012		
2013		
2014		
2015		

ii) Has NRG considered the use of a fixed reduction factor to adjust Rate 6 to account for the significant reduction in Rate Base that will occur over the period of the IRM? If not, why not?

iii) Has NRG any evidence to suggest that it is an average performing utility in the selection of a stretch factor?

iv) Has NRG renegotiated its loan with its lenders? If so, please provide a comparison of the old loan facility with the new loan facility in respect of principal amount, interest rate and term. If NRG has not renegotiated the loans please explain why not.

RESPONSE

i)

Year	Rate 6 Rate Base	Decrease In Rate Base Against Prior Year
2011	$ 4,222,558	-$ 243,609
2012	$ 3,978,949	-$ 243,609
2013	$ 3,735,340	-$ 243,609
2014	$ 3,491,731	-$ 243,609
2015	$ 3,248,122	-$ 243,609

If there are no capital expenditures on the IGPC Pipeline going forward, then the rate base underpinning Rate 6 will go down, but NRG is not planning to undertake forecasting as to whether there will be any IGPC-driven capital additions in the future for the purposes of designing its IRM model to adjust rates going forward. Base year rates have been set. The proposed IRM model is not based on forecasting cost items through the IRM term. To do so would nullify the efficiencies associated with moving to an IRM model.

ii) No – it is not consistent with the 3rd generation IRM. Increases are the same for all rate classes, unless there is an approved phase-in of rate adjustments to move revenue-cost ratios within the approved ranges, and a phase-in is needed to mitigate the rate increase in the COS test year.

iii) It is unreasonable to compare NRG's performance to electricity distributors. There is no evidence to suggest NRG should not be considered an average performing utility in the selection of stretch factor (it is the only small gas distributor). There is no basis for using either the lower or higher stretch factor that would be applied to outliers under the electricity 3rd generation IRM

iv) Please refer to answer above under 3(i). NRG's financing and cost of capital are not at issue in phase II. Cost of capital has been set for the base year.