Goodmans LLP

Barristers & Solicitors

Bay Adelaide Centre
333 Bay Street, Suite 3400
Toronto, Ontario M5H 2S7

Telephone: 416.979.2211
Facsimile: 416.979.1234
goodmans.ca

Direct Line: 416.597.6286
rmalcolmson@goodmans.ca

July 21, 2014

VIA RESS, EMAIL AND COURIER

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Attention: Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: Interrogatories from Northeast Midstream LP ("Northeast Midstream") with respect to Board File EB-2014-0012

We act as counsel to Northeast Midstream in the above-captioned matter.

In accordance with the Board's Procedural Order No. 1, please find attached Northeast Midstream's Interrogatories to the applicant, Union Gas Limited.

Yours very truly,

Goodmans LLP

Robert Malcolmson
RZM/pg

Attachments

Copy: Karen Hockin, Union Gas
Charles Keizer, Torys
Intervenors (by e-mail)

6352092

Filed: July 21, 2014
EB-2014-0012

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

AND IN THE MATTER OF an Application by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998*, for an order or orders approving rates and other charges for an interruptible natural gas liquefaction service.

INTERROGATORIES ON BEHALF OF

Northeast Midstream LP

Interrogatory

Exhibit A, Tab 1, Page 1, Lines 9-11

Union will build new facilities adjacent to Hagar and provide LNG to wholesale distributors. The primary use of the LNG is a vehicle transportation fuel. Under O. Reg. 161/99, LNG in this context qualifies as "motor vehicle fuel gas".

1. Spark ignited engines have limitations on the amount of ethane, nitrogen and C6+ components that are acceptable in LNG. These components are not an issue for utility uses of LNG, but can cause engine issues when LNG is used as a transportation fuel. Notwithstanding historical gas quality information and current tariff limits of TCPL, there is a trend in the western Canadian sedimentary basin (WCSB) toward the production of much richer unconventional natural gas. The share of ethane and heavier components in this sales gas from WCSB is expected only to increase over time on the TCPL Mainline that feeds Hagar. Please indicate whether the current capital estimate includes the cost to add a dethanizer, nitrogen rejection column, and a C6+ stripper to the existing liquefaction unit.

2. Please state how Union plans to dispose of any of the heavier components stripped from the feed gas in order to comply with transportation fuel specifications. What are the estimated disposal costs and where are they reflected in Union's rate proposal?

3. Please state how the energy content of the heavier components that are stripped out of the gas will be accounted for on a rate making basis?

4. As unconventional gas ethane content and gas density changes on a daily basis and to the extent that these changes are not blended out through mixing within the TCPL system,

please indicate the capability of the Hagar plant to change its refrigerant composition to accommodate transportation fuel specifications. To the extent that this capability does not exist, what are the estimated costs of creating this capability and where are those costs reflected in Union's rate proposal?

5. Please specify the extent to which producing transportation grade LNG will increase the cost of the liquid in storage that is held for system integrity use. Are such costs, if any, reflected in Union's rate proposal?

Interrogatory

Exhibit A, Tab 1, Page 1, Lines 13-15

13 However, as liquefaction services at
14 Union's Hagar facility will be provided within a regulated regime the use of the LNG could be
15 expanded beyond motor vehicle fuel without further regulatory approvals.

6. Please describe sales plans for LNG from Hagar beyond the on-highway market, since no other markets are identified in the application.

7. Please specify which other markets under consideration do not require regulatory approval and that might require regulatory approval.

Interrogatory

Exhibit A
Page 4, Table 1

Table 1
Summary of Forecast Activity, Proposed Rate and Revenue

Line No.	Particulars	Forecast (GJ) (1)	Proposed Rate ($/GJ)	Revenue ($000's)
		(a)	(b)	(c) = (a x b/1000)
1	Liquefaction:	1,662,080	5.096	8,470
2	Average Revenue/Year (line 1 / 4)			2,117

Note:
(1) As per Exhibit A, Tab 2, Schedule 5, line 9, column (e). The liquefaction forecast is based on 415,520 GJ of average annual activity from September 1, 2015 to December 31, 2018.

8. Union forecasts a total demand of 1,662,080 GJ over a period of 40 months. Exhibit A, Tab 2, shows the demand growing from 203,520 GJ in 2015 (annualized) to 678,400 in 2018, yielding a levelized demand of 425,520 GJ per year to 2018.

    (a) Please describe how Union arrived at the annual liquefaction sales figures that underpin the sales forecast in Table 1.

    (b) Please provide the expected sales forecast for 2019 to 2035.

    (c) Please describe what, if anything, would prevent Union's LNG customers from switching to new, lower cost sources of liquefaction services, leading to an erosion of customers supporting the L1 rate.

    (d) Please provide the assumptions Union makes about market forces, including but not limited to the barriers facing customers converting to LNG, the ability of OEMs, engine companies and others to deliver LNG solutions at a reasonable price, and the price of oil versus natural gas.

<u>Interrogatory</u>

Exhibit A Tab 1, Page 8, Lines 14-16

14 The renewed interest in CNG and LNG as a vehicle fuel is not isolated to Ontario. This market is
15 actively being pursued in a number of other regulatory jurisdictions in both the United States and
16 Canada.

9. In the United States in recent years, a number of local distribution companies have either sold their LNG assets to private companies or spun-off their LNG assets into un-regulated businesses to market and sell LNG as a replacement for diesel. For example, In 2011 Pivotal LNG purchased a 5,000 GJ/day LNG facility located in Trussville, Alabama, from the Utilities Board of the City of Trussville. In 2013, Citizens Energy Group in Indianapolis vested its LNG assets with Kinetrex Energy to supply LNG to fuel UPS tractor trailers in the Midwest. Please identify to what extent Union has evaluated the cost-effectiveness of selling the Hagar facility to a private entity and then contracting back the required system integrity services on behalf of Union North customers.

<u>Interrogatory</u>

Exhibit A Tab 1, Page 10-11

20 A major barrier to the broader market adoption of LNG in Ontario is the lack of local supply.

Filed: July 21, 2014
EB-2014-0012

The plant at Hagar is well positioned to act as a market starter in Ontario. It is relatively close to the prime Toronto market; volumes are sufficient to contribute to the government's drive to reduce CO2 emissions; but small enough to limit any risk resulting from a slow market adoption.

10. Northeast Midstream is an Ontario limited partnership that has been approved to build a new LNG production facility in Thorold, Ontario, to serve the Great Lakes region, including all of Ontario. Thorold will have the capacity to liquefy up to 33,000GJ/day of natural gas, or 12 million GJ per year, which is ten-times the total capacity of Hagar. Please state whether Union's revenue projections take into account the operation of the Thorold facility.

<u>Interrogatory</u>

Exhibit A Tab 1, Page 10, Lines 5-11

Union had discussions with several parties looking to enter Ontario's LNG distribution market. To assess and verify the market interest in the service, Union conducted a non-binding call for Expressions of Interest ("Expression") for volumes of LNG from the Hagar plant. The Expression was initiated on February 18, 2014 and was open for submissions up to March 7, 2014. As part of the Expression, parties were asked to provide a maximum daily quantity required as well as annual and monthly consumption estimates. Six parties expressed interest in purchasing LNG. Table 2 shows the parties minimum annual commitments.

11. Union has obtained six expressions of interest for a total of 700,633 to 810,633 GJ per year. Contract tenors range from three to ten years, although two of the six respondents declined to specify a term. The open season document provides an indicative price of $5.54 to $6.93 /GJ, plus the natural gas commodity, which is 10% to 20% higher than the proposed L1 Rate, and Union has not yet signed a precedent agreement with any customer. Please specify whether the minimum annual commitments in Table 2 reflect the price indicated in the open season or the price of the proposed L1 Rate.

12. Please explain why Union hasn't waited until it signed precedent agreements sufficient to support the planned expansion before making its application for the L1 Rate.

13. Without one or more precedent agreements for capacity as evidence to support the rate application, please indicate what probability Union assigns to each of these expressions of interest that it will convert into a precedent agreement.

14. Please provide a template precedent agreement that Union is using with potential customers.

15. Please state whether there are other potential customers who did not respond to the open season, but who have subsequently indicated they would sign up for capacity at Hagar. If so, please indicate the number of potential customers and their potential minimum annual commitments.

16. Please state how Union intends to reconcile the difference between the short-term nature of the indicated tenors with the life of the expanded asset.

17. What is the per GJ market rate for LNG at the present time?

<u>Interrogatory</u>

Exhibit A Tab 1, Page 11, Lines 5-8

Hagar is located near Sudbury Ontario, and has been in operation since 1968. Union's Sudbury system is within TransCanada's ("TCPL") delivery area known as Union Northern Delivery Area ("NDA"). The Hagar facility is interconnected with Union's Sudbury Lateral pipeline system.

18. Hagar is connected to the TransCanada (TCPL) Mainline, near Sudbury. In March, 2014, TCPL informed the National Energy Board that it will make an application seeking approval for the Energy East Pipeline, a 4,600-kilometre pipeline that will carry 1.1-million barrels of crude oil per day from Alberta and Saskatchewan to refineries in Eastern Canada. Currently, the Energy East project calls for converting one of the existing pipelines that supplies Union North from natural gas to an oil transportation pipeline. Please indicate the expected impact on gas availability and deliverability for NDA customers if Energy East goes forward and the natural gas flowing from Western Canada to central and eastern Canada is reduced by 30% to 40%.

19. Please state whether the reduction in flow is expected to create new supply constraints and price volatility for NDA customers, especially in the winter months, such as gas customers experienced in New England in 2014.

20. Please state whether Union expects the Hagar LNG facility to operate differently than it has in recent years to ensure reliability and deliverability in the NDA if the Energy East Pipeline proceeds.

21. Please indicate whether Union anticipates the need to build additional natural gas infrastructure to alleviate the potential supply shortfall from Energy East, the cost of which will be recovered from NDA customers.

22. How would a supply shortfall in the range of 30-40% affect storage practices at Hagar?

<u>Interrogatory</u>

Exhibit A Tab 1, Page 13, Lines 13-21, Page 14 Lines 1-9

Union proposes to sell the excess LNG liquefaction capabilities to various parties at its proposed Board-approved rates. In order to provide this service, Union will use excess liquefaction capability that currently exists as a result of Hagar's current operations. Union will also facilitate incremental Hagar storage space through the replacement of existing outdated measurement technology with new measurement technology that will increase the working capacity of the LNG tank.

The provision of this new service will not impact the system integrity space or deliverability available from Hagar to meet Union North system integrity requirements. Further, Union's ability to liquefy sufficient quantities of natural gas to ensure the tank is at or above 0.6 PJ prior to the beginning of the peak winter season will not be affected.

Excess Hagar Liquefaction

Excess liquefaction capability exists at Hagar because liquefaction is currently only required to replace LNG volumes vapourized as a result of a system integrity event or regularly occurring boil off. Liquefaction is also not available during maintenance periods. This means that excess liquefaction capability exists on an interruptible basis throughout the year. It is this excess

9 liquefaction that Union intends to market to its LNG customers.

23. Union Gas is proposing to use tank inventory management techniques to make unused liquefaction capacity available for sales of LNG as a transportation fuel. Irrespective of the tank management argument, the interruptible service will increase the duty cycle of the liquefaction equipment, which is 46 years old, and nearing the end of its useful life. Please identify the make, year, and type of liquefaction system at Hagar, as well as the composition of the refrigerant(s) used.

24. Please specify the annual load factor of the Hagar liquefaction unit over the past 10 years, including the number of stop/starts per year.

25. Please specify the expected annual load factor of the Hagar liquefaction unit over the life of the expansion, including the projected number of stop/starts per year.

26. Please provide the historical Mean Time to Failure (MTTF) and Mean Time To Repair (MTTR) figures for the liquefaction equipment over the past 10 years.

27. Please indicate whether the Mean Time to Failure (MTTF) and Mean Time To Repair (MTTR) figures for the liquefaction equipment is expected to increase over the future life of the project.

28. Please indicate whether the future load factor is expected to compromise reliability or the plant's ability to fulfill its prime function of supplementing system integrity.

<u>Interrogatory</u>

Exhibit A Tab 1, Page 14-15, Lines 12-22 and 1-6

12 Union proposes to increase the working storage space available at Hagar by upgrading the
13 inventory measurement system from the current "tank-o-meter" measurement system to a radar
14 measurement system. The existing "tank-o-meter" measurement system used to measure LNG
15 inventory at Hagar was installed in 1968 and is accurate to +/- 0.97 ft of tank height. The tank-o-
16 meter calculates the LNG storage tank fill height by using a pressure tube installed within the
17 storage tank.
18
19 Union proposes to replace the current height measurement equipment with a radar measurement
20 system. This radar measurement system can measure the height of LNG in the tank without any

physical contact with the LNG surface, and without the need for inside-tank components that require service. Thus, the system provides continuous, reliable and highly accurate level data to +/- 0.007 ft.

The improvement in measurement accuracy will allow Union to maximize the use of the tank safely and with certainty. This will effectively increase the amount of working storage space available by an estimated 7,000 GJ. The estimated installed cost of the radar measurement system is $200,000.

29. Please specify to what extent the stated Tank-O-Meter inaccuracy is due to the inherent physical limitations of the equipment or other factors, including but not limited to liquid density caused by boil off and nitrogen rejection.

30. Please provide evidence that tank levels have not been higher than indicated given the acknowledgement that the current tank level system is stated within a plus/minus level of accuracy.

31. Please state whether it is possible that the actual tank levels have historically been higher than indicated due to level measurement inaccuracy, and that more accurate measuring equipment may not provide for the anticipated additional storage space.

32. Please confirm that the tank impoundment volume can accommodate the proposed increase in LNG stored.

33. Please state whether the combination of higher tank levels and potential for increased LNG density in kg/m3 due to increased ethane and C6+ content present any issues with the tank foundation loading.

34. Please state whether Union uses a travelling density/temperature probe to detect stratification in tank volume density that can lead to a tank roll over. If so, how does the level data collected from that device compare historically to the Tank-O-Meter level data?

<u>Interrogatory</u>

Exhibit A Tab 1, Page 15, Lines 8-13

Union proposes to recover the $200,000 capital cost as part of the liquefaction rate. Union will

9 utilize the incremental LNG storage space to manage differences between natural gas deliveries
10 for liquefaction and quantities of LNG dispensed. The space will allow Union to continue to
11 dispense LNG to its customers during Hagar liquefaction equipment maintenance periods. To
12 ensure there is no significant accumulation of stored gas, the deliveries and takings will be
13 managed contractually. Any storage required is temporary and the result of timing differences.

35. Please confirm the number of days of liquefaction that 7,000 GJ is capable of storing, with respect to the nominal liquefaction capacity of the plant and the maximum allowable take under the proposed L1 rate.

36. Please confirm whether the 7,000 GJ of storage is a hard limit for L1 rate customers, and that Union does not intend to "borrow" storage from the system integrity tank to make interruptible deliveries of LNG.

37. Please identify any scenarios where Union anticipates that interruptible deliveries of LNG will require more than 7,000 GJ of storage.

38. Please indicate the accuracy of the new radar system to measure an additional 7,000 GJ of storage in a 648,000 GJ tank at volume intervals varying from empty to full.

39. Please quantify in terms of hours /days the terms "temporary" and "timing differences" in line 13 above.

Interrogatory

Exhibit A Tab 1, Page 15 – 16, Lines 16-20 and Line 1

16 Union is proposing to provide an interruptible liquefaction service. This service will be provided
17 under the new Rate L1 rate schedule. Included in this service is the option for Union to provide
18 the customer an accompanying natural gas supply service and natural gas transportation service
19 to Union's NDA. The natural gas supply service and transportation service will be provided
20 under the proposed changes to new and existing Board approved rate schedules; proposed Rate
1 described in more detail in Exhibit A, Tab 2.

Filed: July 21, 2014
EB-2014-0012

40. The service is identified as "interruptible" throughout the application, yet utilities typically do not build infrastructure for "interruptible" service. But the L1 Rate Schedule (Tab 2, Schedule 3) indicates that the customer is subject to an annual minimum charge of liquefaction services. This "take-or-pay" feature seems to imply that the L1 rate is actually for "firm" delivery of LNG services for a specified quantity on an annual basis. Please clarify on what basis the L1 rate of $5.096 per GJ is for "interruptible" or "firm" service?

41. What is the expected contract tenor for L1 service?

42. What are the renewal rights, if any?

43. Will customers provide and maintain evidence of creditworthiness throughout the term of the L1 service agreement? Where is creditworthiness factored into the rate proposal?

44. What flexibility will customers have in terms of the timing for nomination for service, liquefaction, storage, and dispensing under the proposed L1 rate of $5.096?

45. What is the minimum contracted quantity that will trigger Union to make a final investment decision and build facilities?

46. Please describe the rationale for the price ceiling for short-term "interruptible" service at three-times the proposed rate of $5.096 / GJ. Will the short-term rate have a floor?

47. How will Union set the price (i.e., a daily auction mechanism) and will procurement be open access or restricted?

48. Please describe any limits to prevent Union from "dumping" short-term LNG volumes into the transportation fuel market at a discount to the L1 proposed rate, and potentially undercutting other suppliers.

49. Please describe how any spot market premiums or losses could impact the rate base.

<u>Interrogatory</u>

Exhibit A Tab 1, Page 18, Lines 14-21

14 Union proposes to allocate a storage space entitlement of 7,000 GJs in aggregate to
15 accommodate this service within the main Hagar storage tank. As described above, Union's
16 ability to use this space is a result of the installation of a new radar measurement system which
17 increases the working capacity of the LNG tank. The incremental storage space allows Union to

continue LNG dispensing service to its customers during Hagar liquefaction equipment maintenance periods and to manage the timing differences between natural gas delivered for liquefaction and LNG dispensed. Union will not be able to dispense LNG during periods of vapourization.

50. Please state whether liquefaction and dispensing of interruptible LNG volumes will be carried out during periods of tank replenishment to achieve the full level identified for system integrity.

51. If the tank volume is less than the maximum volume required to cover system integrity, please state how Union will prioritize demands for liquefaction for system integrity versus requests for interruptible LNG.

<u>Interrogatory</u>

Exhibit A Tab 1, Page 19, Lines 2-19

Customers will commit to a liquefaction forecast prior to their contract year stipulating dispensing quantities and timing on a monthly basis. The total of the forecast quantity for an individual customer is defined as the customer's Minimum Annual Volume. Each month, the customer must deliver, or arrange for Union to deliver on their behalf, to the Union NDA the equivalent amount of natural gas as to the quantity of LNG that will be dispensed. This will result in a forecast zero balance at the end of each month.

Approximately 15 days prior to each month, the customer will be allowed to alter its monthly forecast and natural gas supply quantity: i) down by a maximum of 20% (to 80% of the original forecasted quantity); ii) leave it at the original forecast amount; or, iii) increase it, subject to Union's approval, for the excess quantity above the original forecasted quantity. On a customer aggregated basis, the sum of all daily supplies cannot exceed 1,860 GJ/d annually.

The customer will be invoiced monthly for the greater of; i) 80% of their original forecast

quantity; ii) the original forecast quantity; or, iii) the approved increased quantity. At the end of the contract year, if the customer has not met its Minimum Annual Volume commitment within the 12 months, any quantity shortfall will be invoiced in the 13th month for the liquefaction component only (i.e. no natural gas commodity or transport fees).

52. Please confirm the minimum contract tenor for the proposed L1 Rate.

53. Please confirm the minimum daily quantity on a “take-or-pay” basis.

54. Please confirm the minimum monthly quantity on a “take-or-pay” basis.

55. Please state whether customers can “bank” LNG deliveries on an inter-monthly basis? (In other words: Can a customer who has been invoiced for one month of service, but not taken delivery of the LNG in that month, take delivery of the LNG it has already paid for in a following month in addition to the following month’s quantity?)

56. Please indicate the remedies available to L1 customers in the event that Union cannot meet the Minimum Annual Volume commitment under the L1 rate due to a high utilization of the plant for system integrity purposes, unplanned outages, and the like.

<u>**Interrogatory**</u>

Exhibit A Tab 1, Page 20, Lines 2-9

In order to facilitate the dispensing of LNG into tanker trucks, modifications to existing Hagar facilities and additional facilities are required.

Union will invest an estimated $8.7 million in project capital costs. These costs include the installation of the radar measurement system as well as valves and piping that will allow LNG to flow to dispensing facilities plus the construction and installation of piping and a LNG dispensing/pumping skid and weigh scales required to measure the LNG transferred into the tanker truck. A breakdown of the total capital costs of $8.7 million is shown in Table 3.

57. The Hagar plant was placed in service in 1968. Since that time, code requirements for the design, construction and operation of LNG facilities have evolved substantially. The current Hagar plant is grandfathered with respect to current code requirements. In North

America, substantive changes to LNG plant equipment or operations have resulted in the plant's operation and design being reviewed against current code requirements. The current code covering LNG facilities is CSA-276-11 Liquefied Natural Gas (LNG) Production, Storage, and Handling. This code requires several design features that may be difficult to implement in the existing plant. There are a wide range of design and operating requirements in the CSA code and implicit in current industry practices that may be costly or even impossible to retrofit to the plant. Please indicate whether Union has filed or intends to file for an amendment to its Environmental Compliance Approval from the Ontario Ministry of the Environment.

58. Please indicate whether the expansion or the associated road widening will require an environmental impact assessment, approval from the town/municipality, and/or consultations with local residents.

59. Please confirm that the Hagar plant will be in compliance with CSA 276-11 upon completion of the expansion.

60. Please provide design LNG spill scenarios that have been modeled, showing that the resulting gas cloud down to a level of 50% LEL stays on the property along with separation distances.

61. Please provide design fire scenarios that have been modeled, showing that thermal radiation heat flux rates at the property line fall within specified limits.

62. Please provide a Quantitative Risk Analysis that has been developed and/or submitted for approval to the TSSA.

63. Please indicate whether the capital cost of the plant modifications and rate calculation include an allowance for each of these additional requirements.

64. Would these additional requirements influence how the current functional asset allocation is structured, particularly land costs attributable to code imposed separation distances?

<u>Interrogatory</u>

Exhibit A Tab 1, Page 21, Lines 2-6

2 Union is forecasting total incremental O&M expenses of $1.072 million per year by 2018.

3 These incremental O&M expenses are driven by the increased usage of the liquefaction

4 equipment at Hagar associated with the provision of the proposed liquefaction service. Table 4

5 provides a detailed breakdown of the forecasted incremental O&M expenses from September

6 2015 to December 2018.

65. Please indicate whether the O&M budget includes additional human, financial, physical, and knowledge resources that are required to execute an aggressive market growth business strategy to supply LNG services versus a utility business strategy of operating gas infrastructure.

66. Please indicate how the O&M budget takes into account the cost of increasing the load capacity of the liquefaction equipment.

<u>Interrogatory</u>

Exhibit A, Tab 2; Exhibit A Tab 2, Schedules 1-6 and Exhibit A, Tab 2, Attachment A

Northeast Midstream retained Crowe Soberman to analyse the applicant's cost allocation and rate design as set out in the above noted Exhibits. Crowe Soberman prepared a report dated July 17, 2014 (the "Crowe Soberman Report"). The following interrogatories are based upon the Crowe Soberman Report and where indicated refer to the Crowe Soberman Report. The Crowe Soberman report is attached as Schedule 1 to Northeast Midstream's interrogatories.

67. Please confirm that the Board-Approved 2013 revenue requirement for the Hagar facility would be equivalent to $8.223/GJ, assuming a liquefaction volume of 751,950 GJ per year (648,000 GJ per year for system integrity and 104,000 GJ per year for "boil-off")?

68. Please confirm that the costs (other than compressor fuel) assigned to "Variable Costs" are based on the "boil-off" replacement of 104,000 GJ per year only.

69. Union has assigned $842,000 of a total of $1,463,000 in fixed O&M to storage. Please comment on the reasonableness of assigning $842,000 of a total $1,463,000 in fixed O&M to storage, which is an inherently passive activity, when liquefaction is typically the most labour and maintenance intensive activity at an LNG plant.

70. Please comment on the following observation in the Crowe Soberman Report on Page 5 concerning different time periods assigned to depreciation and revenue requirement in the Union application:

> "We do note that there are some observations, which may be made regarding the data on Appendix B, and/or regarding the calculation of the average costs and revenue requirement. Thus, for example, it appears that the plant investment is assumed to have been made for approximately 4 months of 2015, while depreciation is included for 6 months of 2015. However, subsequently, the revenue requirement is considered over 4 complete years, and the average liquefaction volume (of 415,520 GJ) is also calculated over 4 complete years."

71. Please comment on the following observation in the Crowe Soberman Report on Page 5, and explain why the average cost of compressor fuel is $1.44 per GJ of LNG produced for system integrity and only $0.73 per GJ of LNG produced for interruptible LNG service:

> "We also note that the assumed compressor fuel average annual cost is $303,000 for average liquefaction of 415,520GJ per annum. By comparison, from Appendix A, it appears that (for 2013) the compressor fuel cost was estimated to be $1,085,000 for (apparently) average liquefaction of 751,950 GJ. We do not have sufficient information to explain the (relatively) lower compressor fuel cost reflected on Appendix B."

72. Please state whether Section 1 "Original Plant Operation" and Section 2 "Proposed Plant Expansion" in Appendix C of the Crowe Soberman Report is a fair and reasonable summary of the revenue requirement following the proposed expansion described in the Application by Union Gas.

73. Following the proposed expansion, please confirm that required revenue for system integrity operation would be $7.159/GJ, while the required revenue for supplying interruptible LNG under the proposed L1 rate would be $4.617/GJ (system integrity rate is before removing a nominal amount for storage costs transferred to new business).

74. Please indicate whether you agree with the following observation in the Crowe Soberman Report on Page 6:

> "Notwithstanding the above, we have identified an apparent error in the Union Gas calculations, and we have shown a revised calculation on Appendix C. When Union Gas pro-rate their calculated pre-expansion liquefaction rate (of $2.325/GJ) to 167 days, they do not take into account the fact that the LNG commercial business envisages average production of 415,520 GJ, while the calculated pre-expansion liquefaction rate is based on an annual volume of 751,950 GJ."

75. Please confirm that a portion of the liquefaction annual revenue requirement should be allocated to the LNG commercial business (calculated on Appendix C of the Crowe Soberman Report to be $800,000 and based on 167/365 days of the pre-expansion liquefaction revenue requirement of $1,748,000).

76. Please confirm that the required revenue for the LNG commercial business should increase from $4.617/GJ to $5.478/GJ after correcting for the error identified in IR 74 above.

77. Please comment on the following observation in the Crowe Soberman Report on Page 6:

> "We note that the calculated number of days required for the LNG commercial business (averaging 167 days) is based on (stated) assumed plant liquefaction capacity of 3,186 GJ/day. If one assumed operation of the plant for (say) 300 days per annum, this would result in annual liquefaction capacity of 955,800 GJ per annum. This raises some concern regarding the capacity of the plant to both (i) produce 415,520GJ for LNG commercial business customers, and (ii) recycle inventory and replace "boil-off" at the production rate of 751,950GJ per annum (the foregoing amounts total 1,167,470 GJ per annum)."

78. Please provide the actual liquefaction and vaporization quantities over the past 10 years, showing both the quantities of LNG vapourized for system integrity and the quantities lost to "boil-off".

79. Please comment whether it is fair and reasonable to adjust the annual liquefaction capacity for system integrity from 751,950GJ to 425,000GJ (including LNG for vaporization and "boil-off").

80. Please indicate whether it is fair and reasonable to assume that 20% of the storage cost should be allocated to LNG commercial customers, since the anticipated L1 volume is 678,000 GJ in 2018 and the actual storage is 648,000 GJ.

81. Please indicate whether Crowe Soberman's revised calculation, which results in required revenue for the LNG commercial business of $6.885/GJ (before considering distribution costs), is a reasonable basis for determination of the LNG commercial business revenue requirement based on the information available.

82. Please comment on the Crowe Soberman view that it is more reasonable to allocate costs (or plant) which cannot be directly assigned after the proposed expansion, rather than before.

83. Is it correct that Union Gas and KPMG have allocated the costs of liquefaction, vapourization and storage to the new LNG business before considering the proposed plant expansion that is necessitated by the new LNG business?

84. Please provide the cost allocation for liquefaction, vapourization and storage taking into account the proposed plant expansion that is necessitated by the launch of the new LNG business.

85. Is it KPMG's expert opinion that allocating costs after taking into account the proposed plant expansion is a more reasonable apportionment of costs than allocating costs prior to the consideration of the proposed plant expansion?

Filed: July 21, 2014
EB-2014-0012

86. Under the cost allocation approach adopted by Union Gas and KPMG, it appears that the new LNG business is being effectively cross-subsidized and existing natural gas customers are failing to share fully in the benefits of the efficiencies arising from the plant expansion. Please comment

87. Please provide the revenue requirement for the LNG business on a cost allocation basis that takes into account the proposed plant expansion.

88. Please provide the revenue requirement for the new LNG business in a scenario where there is no one time per annum recycling of LNG inventory of 648,000 GJ.

89. Please provide all underlying assumptions to support the projection of assumed capacity of 3,186 GJ per day.

90. What percentage of storage costs did Union Gas and/or KPMG allocate to the new LNG business?

91. As the existing gross plant is valued at $22.8 million, of which $8.2 million is assigned to pre-expansion liquefaction (see Appendix A of the Crowe Soberman Report), and as the proposed expansion reflects further capital investment of $8.7 million, please state whether it is reasonable to suggest that the incremental capital costs alone to provide the L1 service represents approximately 28% of the total post-expansion gross plant (before considering the use of the existing liquefaction facility by the new business).

92. Please comment on whether the ex-post method proposed by Crowe Soberman, which yields the L1 rate of $8.894/GJ, would apportion costs for the new expanded operation in a more equitable manner, and prevents existing natural gas customers from effectively subsidizing L1 customers.

93. Assuming it is reasonable that 20% of the storage cost should be allocated to LNG commercial customers and the ex-post method for cost allocation is equitable for existing customers, do you agree that the revised calculation for the L1 rate is $10.642/GJ as set out in Appendix F of the Crowe Soberman Report.

Crowe Soberman™

Crowe Soberman LLP
Member Crowe Horwath International

2 St. Clair Avenue East, Suite 1100
Toronto, ON M4T 2T5
416.964.7633
416.964.6454 Fax
www.crowesoberman.com

July 17, 2014

Mr. Joshua Samuel
President and CEO of the General Partner
Northeast Midstream LP
42 St. Clair Ave East
Suite 200
Toronto ON M4T 1M1

Dear Mr. Samuel:

Application by Union Gas Limited for approval by Ontario Energy Board of selling price of Liquefied Natural Gas to be produced at a plant in Hagar, Ontario

Introduction

You have asked us, as professional accountants, for assistance in connection with an application by Union Gas Limited ("Union Gas") for approval by Ontario Energy Board ("OEB") of the minimum selling rate of liquefied natural gas ("LNG") in connection with the proposed expansion of a plant in Hagar, Ontario in order to produce LNG for sale to commercial customers.

You have advised us that Northeast Midstream LP ("Northeast") have been granted the status of intervenor in the rate application hearing.

Our work has been limited to an assessment of the business assumptions employed by Union Gas, relying upon information contained in their rate application. We do not have expertise regarding the OEB rate approval process, or regarding certain technical aspects of the required calculations (for example, the method of derivation of the "Return on Rate Base" on assets employed in the relevant business).

For the purposes of this letter, we have relied upon information contained in the Union Gas application dated May 16, 2014, including underlying discussion of the relevant calculations, and including a report prepared by KPMG LLP ("KPMG") dated May 12, 2014.

Other than as specifically stated in this letter (if applicable), we have not audited or attempted to verify the information provided to us in connection with our work.

Our analysis is based on the information provided to us to the current date. Should further information be provided, we reserve the right to amend our calculations.

Restrictions of use

This letter is not intended for general circulation or publication, nor is it to be reproduced or used for any purpose other than that stated above. We do not assume any responsibility for losses occasioned to you or other parties as a result of the circulation, publication, reproduction or use of this letter or its contents contrary to the provisions of this paragraph.

We do not preclude the inclusion of this letter in its entirety by Northeast in connection with any submission made as intervenor in the rate application hearing.

Union Gas application

Based on the information provided, Union Gas operates a natural gas liquefaction plant in Hagar, Ontario in which natural gas may be liquefied and stored for "emergency" use – if necessary – in servicing Union Gas natural gas customers. Union Gas proposes to expand the plant to allow it to produce LNG for sale to commercial customers (the "LNG commercial business").

LNG would be made available for sale on an interruptible basis, i.e. the plant's first priority would be in ensuring the availability of natural gas to Union Gas natural gas customers.

Union Gas have requested OEB approval for a minimum selling price of **$5.096/GJ**. Based on their application, this amount includes **$0.482/GJ** related to the recovery of costs incurred in operation and maintenance of a joint natural gas distribution system which allows natural gas to be received at Hagar. The balance of the application selling price (of **$4.614/GJ**) relates to calculated liquefaction or storage costs.

You have expressed concern regarding the assumptions applied by Union Gas in developing their rate proposal, and that – in essence – the rate they have determined is too low. Our analysis has been designed to consider the reasonableness or otherwise of the calculations developed by Union Gas (or, on their behalf, by KPMG).

Our role

In order to assist you, we have developed analysis which summarizes the calculations underpinning the rate application. In addition, for reasons which are described later in this letter, we have developed additional analysis which offers alternate rate calculations. At each stage, we offer comment or explanation regarding the analysis performed.

Because of your urgent need for our analysis, and in light of the relatively small unit amount involved, we have not attempted to review the calculations relating to the natural gas distribution system. Therefore, where applicable, the unit cost calculations set out in this letter (or in our attached analysis) should be compared to the application unit price of **$4.614/GJ**, before recovery of distribution costs is considered.

We have not attempted to determine the price adjustments, if any, which should be considered to take into account the fact that Union Gas are proposing to offer LNG to customers on an "interruptible" basis. (We note that no such price adjustments are reflected in the calculations supporting the Union Gas rate application.)

Approach adopted by Union Gas

In their report, KPMG refer to the overall approach adopted by Union Gas in developing their calculations. In essence, KPMG state that LNG customers should absorb incremental costs incurred and share in the existing costs. While we agree with this overall approach, we have concerns regarding its execution.

KPMG identify that there are three major functions served within the Hagar plant, namely (i) liquefaction, (ii) storage, and (iii) vapourization.

In essence, the steps taken by Union Gas (or by KPMG, on their behalf) in developing their rate application proposal were as follows:

- Assign existing plant, where possible, to liquefaction, storage or vapourization;
- Allocate other plant and/or existing costs (other than variable costs) between liquefaction, storage and vapourization;
- Allocate a portion of the existing liquefaction costs to the new LNG commercial business (a small portion of the storage cost is also allocated to the new LNG business); and
- Assign the incremental costs of the new LNG commercial business, including variable costs, to that business exclusively.

We note that the above approach may at first glance appear to be conceptually sound. This is because all costs (or plant) which cannot be directly assigned to one of these three major functions are allocated in some manner to each of the three functions, and all incremental costs related to the LNG commercial business are allocated to that business directly. However, it is important to identify that the cost allocation has been made <u>before</u> considering the proposed plant expansion.

Overall, it seems more reasonable to allocate (to the various functions) those costs (or plant) which cannot be directly assigned <u>after</u> considering the proposed plant expansion, rather than <u>before</u> considering the proposed plant expansion. This would allow for a fairer apportionment of costs taking into account the expanded business. In our view, cost allocation prior to the consideration of the proposed expansion results in the provision of tangible benefit to the LNG commercial business at an allocated cost which does not reflect the relative magnitude of the liquefaction business following the expansion.

We suggest that, under the approach adopted by Union Gas, LNG commercial business customers are effectively subsidized, and existing natural gas customers are correspondingly penalized, because existing natural gas customers fail to share in the full benefit of the efficiencies arising from the plant expansion.

Analysis attached to this letter

In order to assist you, we have attached six appendices to this letter (Appendices A to F, attached). We explain and offer observations regarding each appendix in the subsequent paragraphs.

We draw to your attention that there may be minor rounding differences between the amounts shown on the attached appendices and the amounts which appear in the Union Gas rate application.

Appendix A

On Appendix A, we have summarized the cost allocation and revenue requirement for the existing business based on the (stated) board-approved revenue requirement for 2013. From this appendix, it can be seen that, for a total revenue requirement of **$6,183,000**, almost half is allocated to storage (allocation of $2,687,000) or inventory (allocation of $252,000) (these amounts together total **$2,939,000**).

We have also shown on Appendix A the relevant unit costs based on assumed liquefaction volume of **751,950GJ** (which we understand represents "boil off" replacement of **104,000GJ** and the assumed one-time per annum recycling of inventory of **648,000GJ**). The average revenue requirement is **$8.223/GJ**.

We have two important observations relating to the data on Appendix A:

- There is information which suggests that inventory has not recycled one-time per annum (therefore the revenue requirement per unit would be correspondingly higher based on lower liquefaction volume);
- The costs (other than compressor fuel) which are assigned to "Variable Costs" are based on "boil off" replacement of **104,000GJ** per annum only. Therefore, there appears to be an inconsistency between an assumed liquefaction volume of **751,950GJ** per annum and assumed variable costs based on liquefaction of **104,000GJ** per annum.

We draw to your attention that (subject to rounding) the unit amounts of **$2.325/GJ** (for liquefaction) and **$3.573/GJ** (for storage) set out on Appendix A also appear on Schedule 6 of the Union Gas rate application.

You have indicated to us that you question the allocation of remaining (unassigned) plant in the same ratio as the assigned plant, given the (high) proportion allocated to storage. We do not have sufficient knowledge of the business in order to comment in this regard. While storage is essentially a passive activity, we do note that the (present) primary function of the Hagar plant is to maintain sufficient storage of LNG in order to be able to service Union Gas natural gas customers at all times.

Appendix B

On Appendix B, we have summarized the incremental costs of the proposed LNG expansion (presented by Union Gas for the years 2015 to 2018) based on the financial information set out in the Union Gas rate application. However, for this purpose, we have separated variable costs and compressor fuel from other liquefaction costs.

We do note that there are some observations which may be made regarding the data on Appendix B, and/or regarding the calculation of the average costs and revenue requirement. Thus, for example, it appears that the plant investment is assumed to have been made for approximately 4 months of 2015, while depreciation is included for 6 months of 2015. However, subsequently, the revenue requirement is considered over 4 complete years, and the average liquefaction volume (of **415,520GJ**) is also calculated over 4 complete years. We have not attempted to make any adjustment in respect of these observations.

We also note that the assumed compressor fuel average annual cost is **$303,000** for average liquefaction of **415,520GJ** per annum. By comparison, from Appendix A, it appears that (for 2013) the compressor fuel cost was estimated to be **$1,085,000** for (apparently) average liquefaction of **751,950GJ**. We do not have sufficient information to explain the (relatively) lower compressor fuel cost reflected on Appendix B.

We draw to your attention that (subject to rounding) the unit amount of **$3.513/GJ** set out on Appendix B also appears on Schedule 6 of the Union Gas rate application.

Appendix C

On Appendix C, we have recreated the proposed revenue requirement (before considering distribution costs) of **$4.617/GJ** (subject to rounding, this is consistent with the Union Gas rate application on Schedule 6 of that application). This amount includes the incremental revenue per unit of **$3.513/GJ** (from Appendix B) for liquefaction plus **$0.039/GJ** (for storage). The remaining amount equals **$1.064/GJ** which is allocated from previously determined liquefaction costs, based on an apportionment of the pre-expansion liquefaction cost (of **$2.325/GJ**, see Appendix A) for 167 days of 365 days.

Based on the calculations presented by Union Gas, following the plant expansion, the required revenue per unit for the pre-expansion plant operation would be **$7.159/GJ**, while (despite the incremental costs incurred in the expansion), the required revenue per unit for the LNG commercial business would be only **$4.617/GJ**. To some extent, this comparison demonstrates our concern regarding the subsidization of the LNG commercial business by natural gas customers. In addition, the comparison reflects the fact that minimal storage costs were allocated (in the Union Gas rate application) to the LNG commercial business (discussed further below).

Notwithstanding the above, we have identified an apparent error in the Union Gas calculations, and we have shown a revised calculation on Appendix C. When Union Gas prorate their calculated pre-expansion liquefaction rate (of **$2.325/GJ**) to 167 days, they do not take into account the fact that the LNG commercial business envisages average production of **415,520GJ**, while the calculated pre-expansion liquefaction rate is based on an annual volume of **751,950GJ**. This error can be overcome by firstly allocating a portion of the liquefaction annual revenue requirement (calculated on Appendix C to be **$800,000** based on 167/365 days of the pre-expansion liquefaction revenue requirement of **$1,748,000**) to the LNG commercial business, and then re-calculating the per unit revenue requirement for the LNG commercial business. When this correction is made, the required revenue for the LNG commercial business increases from **$4.617/GJ** to **$5.478/GJ**.

We note that the calculated number of days required for the LNG commercial business (averaging **167 days**) is based on (stated) assumed plant liquefaction capacity of **3,186GJ/day**. If one assumed operation of the plant for (say) 300 days per annum, this would result in annual liquefaction capacity of **955,800GJ** per annum. This raises some concern regarding the capacity of the plant to both (i) produce **415,520GJ** for LNG commercial business customers, and (ii) recycle inventory and replace "blow-off" at the production rate of **751,950GJ** per annum (the foregoing amounts total **1,167,470GJ** per annum). We discuss this further below.

Appendix D

On Appendix D, we have set out a revised calculation of the revenue requirement for the LNG commercial business <u>following the intrinsic before plant expansion approach adopted by Union Gas</u> but reflecting certain adjustments which seem reasonable in the circumstances. These adjustments are:

- Based in part upon the capacity concern identified above, and in part upon the fact that (apparently) an annual one-time recycling of inventory has not been required, we adjusted the annual "emergency" liquefaction need from **751,950GJ** to **425,000GJ** (based on assumed recycling of inventory approximately one-time per two years plus annual replacement of "boil-off" of **104,000GJ**);

- We allocated pre-expansion liquefaction costs in proportion to the assumed annual volume required for emergency needs (of **425,000GJ**) and the annual volume required for the LNG commercial business (of **415,520GJ**); and
- We assumed that 20% of the storage cost should be allocated to LNG commercial customers, to take into account that the anticipated volume (reaching **678,000GJ** by 2018) could reasonable demand storage availability (whether or not actually used) equal to 20% of the actual storage of **648,000GJ**.

In addition, on Appendix D, we applied a consistent approach to the determination of the revenue requirement for the LNG commercial business (regarding allocation of a portion of the calculated pre-expansion liquefaction revenue requirement) to that applied in the revised (i.e. corrected) calculation set out on Appendix C.

Our revised calculation (on Appendix D) results in required revenue for the LNG commercial business of **$6.885/GJ** (before considering distribution costs). Overall, and before considering the further analysis described at Appendix E below, this may be a realistic basis for determination of the LNG commercial business revenue requirement based on the information available.

On Appendix D, we did not attempt to adjust the variable costs associated with the pre-expansion business (to take into account the assumed lower volume of pre-expansion liquefaction) because this does not affect the revised calculation of the revenue requirement for the LNG commercial business.

Appendix E

As previously stated, it seems more reasonable to allocate those costs (or plant) which cannot be directly assigned after considering the proposed expansion, rather than before considering the proposed expansion. This would ultimately apportion costs for the new expanded operation in a manner which prevents existing natural gas customers from effectively subsidizing LNG commercial business customers.

By way of example, we note that, in the 2013 board-approved summary, Hagar plant administrative costs are identified as **$1,353,000**. (Note that there does not appear to be any increase in administrative costs in the overall discussion of the proposed plant expansion.)

Based on the method of allocation followed by Union Gas, **$487,000** of these administrative costs are allocated to (pre-expansion) Liquefaction (see Appendix A), of which **45.8%** (167/365 days), or **$223,000** are then allocated to the LNG commercial business. Therefore, at the end of the allocation process, the LNG commercial business is assigned around **16.5%** (being **$223,000** divided by **$1,353,000**) of the plant administrative costs.

By comparison, the existing gross plant is valued at **$22.8 million**, of which **$8.2 million** is assigned to pre-expansion liquefaction (see Appendix A), and the proposed expansion reflects further capital investment of **$8.7 million**. Therefore, after the expansion, the incremental capital cost alone reflects approximately **28%** of the total post-expansion gross plant, before considering the use of the existing liquefaction facility by the new business.

It is our view that the above comparison demonstrates the type of distortion which can arise when the allocation of costs is performed before considering the impact of the plant expansion.

For this reason, on Appendix E, we have recreated the unit revenue requirement allocation results based on allocations after the proposed plant expansion rather than before the proposed plant expansion. We note that, for this purpose, for simplicity, we have made no adjustment for the timing differences between the two sets of data considered, nor have we considered any alternative method of allocating costs and plant to take into account the cost differences relating to the fact that the new LNG dispensing facility would be new while the pre-expansion plant is much older. In addition, we have simply relied upon the "average" gross plant incremental "cost" of **$7,218,000** (based on the average annual investment divided by 4 years), and we have ignored the fact that a (believed) small portion of the capital cost does not relate to the LNG dispensing facility.

The data on Appendix E shows that, after the expansion, based on annual liquefaction of **1,167,470GJ** (which ignores any capacity concern), the average revenue requirement allocated to the LNG commercial business (before any allocation of storage cost, which has not been apportioned on Appendix E) is **$8.894/GJ**. The corresponding amount calculated on Appendix C (in our corrected calculation, and before allocation of storage cost) equals **$5.474/GJ**.

We do not necessarily recommend the specific elements of the plant or cost allocation approach applied on Appendix E, to the exclusion of any other allocation approach. However, the result of the calculation set out on Appendix E illustrates the significant distortion caused by allocation of costs (or plant) before considering the proposed plant expansion, rather than after considering the proposed plant expansion.

Appendix F

On Appendix F, we have essentially reproduced the calculation set out on Appendix E, however we made similar adjustments (to those reflected on Appendix D) regarding (a) recycling of inventory one-time every two years, and (b) allocation of 20% of storage cost to the LNG commercial business.

Subject to the method of allocation of unassigned plant or costs (since alternative approaches may also be reasonable), the result of the Appendix F calculation may reflect the most reasonable assessment of the revenue requirement related to the new LNG commercial business.

On Appendix F, in order to avoid creating additional complexity within our calculations, we did not attempt to adjust the variable costs associated with the pre-expansion business (to reflect the assumed reduced recycling of inventory), although we acknowledge that an adjustment in this regard could be considered.

Our calculation results in a revenue requirement for the LNG commercial business of **$10.642/GJ**.

Summary

In summary, we offer the following observations regarding the proposed LNG rate set out by Union Gas in their rate application.

With regard to the specific calculations contained in the Union Gas rate application:

- Due to an apparent error in their calculation, the proposed rate (before considering distribution costs) should be increased from **$4.617/GJ** to **$5.478/GJ**; and
- Due to concerns regarding underlying assumptions regarding liquefaction volumes and storage requirements, on Appendix D, we offer a revised calculation of **$6.885/GJ**. This calculation continues to follow the <u>before plant expansion</u> approach to allocation of unassigned plant and costs.

From a conceptual perspective, it seems more reasonable to allocate unassigned plant and costs <u>after</u> considering the proposed plant expansion.

If we adopt the technical elements of the methodology applied by Union Gas, subject to use of an <u>after plant expansion</u> allocation approach, the required revenue per unit increases to **$8.894/GJ** (before any allocation of storage costs). (This calculation is subject to the reasonableness of the inventory recycling assumption of one inventory recycling per year.)

When our <u>after plant expansion</u> calculation is further amended to reflect only one inventory recycling every two years, and to allocate 20% of the calculated storage cost to the LNG commercial business, the required revenue per unit equals **$10.642/GJ**.

General

We trust that this letter will be of assistance to you. Should you have any questions, please do not hesitate to contact the undersigned.

Yours very truly

Crowe Soberman LLP

Daniel M. Edwards
Daniel M. Edwards Professional Corporation
Partner, Valuations | Forensics | Litigation

DME/

H:\Litigation2\Soberman\Client\N\Northeast Midstream LP\Report\Letter - Northeast Midstream - July 17.2014.docx

Client: **Northeast Midstream LP**

Regarding: **Calculated minimum selling price of Liquefied Natural Gas**
Proposed expansion of Union Gas Limited plant at Hagar, Ontario

<u>**Contents**</u>

To be read in conjunction with the accompanying letter dated July 17, 2014.

Client: **Northeast Midstream LP**

Regarding: **Calculated minimum selling price of Liquefied Natural Gas**
Proposed expansion of Union Gas Limited plant at Hagar, Ontario

Board-Approved 2013 Revenue

	2013 Data	Liquefaction	Storage	Vapourization	Inventory	Variable Costs	Basic of allocation
	$000	$000	$000	$000	$000	$000	
Hagar LNG - Gross plant	22,768	8,169	12,529	2,070			Calculated for defined assets, then extended
Hagar - Assigned net plant	5,807	2,089	3,344	374			Calculated for defined assets
Hagar - Remaining net plant	5,740	2,065	3,305	370			Allocated based on defined assets
Hagar LNG - Net plant	11,547	4,154	6,649	744	-	-	Calculated for defined assets, then extended
All other net plant	593	213	342	38			Allocated based on net plant
Working capital - gas	3,093				3,093		LNG inventory required for "system integrity"
Working capital - other	235	85	136	15			Allocated based on net plant
Rate base	15,468	4,452	7,127	797	3,093	-	
Required return	1,132	326	522	58	226		Allocated based on rate base
Income tax	131	38	61	7	26		Allocated based on rate base
Property tax	80	29	43	9			Allocated based on gross plant
Depreciation - total	882	342	440	100			Assigned, balance allocated based on net plant
Hagar O&M - Fixed	1,463	526	842	94			Allocated based on net plant
Hagar O&M - Variable *	57					57	Calculated variable costs for 104,000 GJ "boil-off"
Admin O&M	1,353	487	779	87			Allocated based on net plant
Compressor fuel	1,085					1,085	Removed and assigned to "system integrity"
Revenue requirement	6,183	1,748	2,687	355	252	1,142	
Liquefaction volume (GJ)	751,950	751,950	751,950	751,950	751,950	751,950	
Revenue required per unit	$\boxed{8.223}$	2.325	3.573	0.472	0.335	1.519	

* materials, electricity and equipment maintenance

To be read in conjunction with the accompanying letter dated July 17, 2014.

Client: Northeast Midstream LP

Regarding: Calculated minimum selling price of Liquefied Natural Gas
Proposed expansion of Union Gas Limited plant at Hagar, Ontario

Incremental Costs - LNG expansion

	2015	2016	2017	2018	Average	Incremental Liquefaction	Variable Costs
	$000	$000	$000	$000	$000	$000	$000
Hagar LNG - Gross plant	2,818	8,685	8,685	8,685	7,218	7,218	
Hagar - Assigned net plant	2,818	8,378	8,071	7,763	6,758	6,758	
Hagar - Remaining net plant							
Hagar LNG - Net plant	2,818	8,378	8,071	7,763	6,758	6,758	
All other net plant							
Working capital - gas (not considered)							
Working capital - other							
Rate base	2,818	8,378	8,071	7,763	6,758	6,758	-
Required return	163	483	466	448	390	390	
Income tax	(69)	(30)	(15)	(1)	(29)	(29)	
Property tax	14	44	45	45	37	37	
Depreciation - total	154	307	307	307	269	269	
Hagar O&M - Fixed	534	103	207	207	263	263	
Hagar O&M - Variable *	38	186	314	370	227		227
Admin O&M					-		
Compressor fuel	49	247	421	495	303		303
Revenue requirement	883	1,340	1,745	1,871	1,460	930	530
Liquefaction volume (GJ)	67,840	339,200	576,640	678,400	415,520	415,520	415,520
Revenue required per unit (excluding storage costs)	13.016	3.950	3.026	2.758	$\boxed{3.513}$	2.238	1.276

* materials, electricity and equipment maintenance (contractor expenses and technician expenses)

To be read in conjunction with the accompanying letter dated July 17, 2014.

Client: **Northeast Midstream LP**

Regarding: **Calculated minimum selling price of Liquefied Natural Gas**
Proposed expansion of Union Gas Limited plant at Hagar, Ontario

Analysis of Union Gas Limited Calculations

		Volume	2013 Data	Liquefaction	Storage	Vapourization	Inventory	Variable Costs
		GJ	$000	$000	$000	$000	$000	$000
Original plant operation								
Revenue requirement - 2013	Appendix A	751,950	6,183	1,748	2,687	355	252	1,142
Revenue per unit	Appendix A		8.223	2.325	3.573	0.472	0.335	1.519
Liquefaction cost adjustment (167 of 365 days allocated to expansion)			(800)	(800)				
Revised revenue requirement		751,950	5,383	948	2,687	355	252	1,142
Revised revenue per unit			7.159	1.261	3.573	0.472	0.335	1.519
Proposed plant expansion								
Incremental revenue requirement	Appendix B	415,520	1,460	930	-	-	-	530
Incremental revenue per unit	Appendix B		3.513	2.238				1.276
Incremental revenue incl. storage	by deduction	415,520	1,476	930	16	-	-	530
Incremental revenue per unit			3.553	2.238	0.039			1.276
Liquefaction unit revenue adjustment (167 days allocated to expansion)			1.064	1.064				
Required revenue per unit (before distribution costs)			4.617	3.302	0.039	-	-	1.276
Proposed plant expansion - revised								
Incremental revenue incl. storage	see above	415,520	1,476	930	16	-	-	530
Liquefaction cost adjustment (167 days allocated to expansion)			800	800				
Adjusted revenue requirement		415,520	2,276	1,730	16	-	-	530
Adjusted required revenue per unit (before distribution costs)			5.478	4.163	0.039	-	-	1.276

To be read in conjunction with the accompanying letter dated July 17, 2014.

Client: **Northeast Midstream LP**

Regarding: **Calculated minimum selling price of Liquefied Natural Gas**
Proposed expansion of Union Gas Limited plant at Hagar, Ontario

Revised Analysis - Modified Assumptions

1. Original plant operation requires 425,000 GJ per annum
2. Allocate liquefaction costs based on volumes
3. Assume expansion consumes 20% of available storage

	Volume	2013 Data	Liquefaction	Storage	Vapourization	Inventory	Variable Costs
	GJ	$000	$000	$000	$000	$000	$000
Original plant operation							
Revenue requirement - 2013	425,000	6,183	1,748	2,687	355	252	1,142
Revenue per unit		14.548	4.113	6.322	0.835	0.593	2.687
Liquefaction cost adjustment (allocated based on respective volumes)		(864)	(864)				
Storage adjustment (20% to plant expansion, capacity increase ignored)		(537)		(537)			
Revised revenue requirement	425,000	4,783	884	2,150	355	252	1,142
Revised revenue per unit		11.254	2.080	5.059	0.835	0.593	2.687
Proposed plant expansion							
Incremental revenue requirement	415,520	1,460	930	-	-	-	530
Incremental revenue per unit		3.513	2.238				1.276
Liquefaction cost adjustment (allocated based on respective volumes)		864	864				
Storage adjustment (20% to plant expansion, capacity increase ignored)		537		537			
Adjusted revenue requirement	415,520	2,861	1,794	537			530
Adjusted required revenue per unit (before distribution costs)		6.885	4.317	1.292	-	-	1.276

To be read in conjunction with the accompanying letter dated July 17, 2014.

Client: **Northeast Midstream LP**

Regarding: **Calculated minimum selling price of Liquefied Natural Gas**
Proposed expansion of Union Gas Limited plant at Hagar, Ontario

Post-Expansion - Revised Allocations	2013 Data	Expansion	After Expansion	*Allocations following similar approaches to those followed on Appendix A (except depreciation)* General Liquefaction	LNG Dispensing	Storage	Vapourization	Inventory	Variable Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000
Hagar LNG - Gross plant	22,768	7,218	29,986	8,169	7,218	12,529	2,070		
				27.2%	24.1%	41.8%	6.9%		
Hagar - Assigned net plant	5,807	6,758	12,565	2,089	6,758	3,344	374		
				16.6%	53.8%	26.6%	3.0%		
Hagar - Remaining net plant	5,740	-	5,740	953	3,088	1,527	172		
Hagar LNG - Net plant	11,547	6,758	18,305	3,042	9,846	4,871	546	-	-
All other net plant	593	-	593	98	319	158	18		
Working capital - gas	3,093	-	3,093					3,093	
Working capital - other	235	-	235	39	126	63	7		
Rate base	15,468	6,758	22,226	3,179	10,291	5,092	571	3,093	-
				14.3%	46.3%	22.9%	2.6%	13.9%	
Required return	1,132	390	1,522	218	705	349	40	212	
Income tax	131	(29)	102	15	47	23	3	14	
Property tax	80	37	117	32	28	49	8		
Depreciation (Depn allocated by gross plant)	882	269	1,151	313	277	481	79		
Hagar O&M - Fixed	1,463	263	1,726	286	928	459	52		
Hagar O&M - Variable	57	227	284						284
Admin O&M	1,353	-	1,353	225	728	360	41		
Compressor fuel	1,085	303	1,388						1,388
Revenue requirement	6,183	1,460	7,643	1,089	2,713	1,721	223	226	1,672
Liquefaction volume (GJ)	751,950	415,520	1,167,470	1,167,470	415,520				1,167,470
Revenue required per unit	$\boxed{8.223}$	3.513	6.546	0.933	6.529				1.432
LNG commercial business unit cost, before considering inventory and storage				$\boxed{8.894}$	General liquefaction plus LNG dispensing plus Variable costs				

To be read in conjunction with the accompanying letter dated July 17, 2014.

Appendix F

Client: **Northeast Midstream LP**

Regarding: **Calculated minimum selling price of Liquefied Natural Gas**
Proposed expansion of Union Gas Limited plant at Hagar, Ontario

Post Expansion - Revised Allocations and Assumptions

1. Original plant operation requires 425,000 GJ per annum
2. Assume expansion consumes 20% of available storage

	2013 Data	Expansion	After Expansion	General Liquefaction	LNG Dispensing	Storage	Vapourization	Inventory	Variable Costs
				Allocations following similar approaches to those followed on Appendix A (except depreciation)					
	$000	$000	$000	$000	$000	$000	$000	$000	$000
Hagar LNG - Gross plant	22,768	7,218	29,986	8,169	7,218	12,529	2,070		
				27.2%	24.1%	41.8%	6.9%		
Hagar - Assigned net plant	5,807	6,758	12,565	2,089	6,758	3,344	374		
				16.6%	53.8%	26.6%	3.0%		
Hagar - Remaining net plant	5,740	-	5,740	953	3,088	1,527	172		
Hagar LNG - Net plant	11,547	6,758	18,305	3,042	9,846	4,871	546	-	-
All other net plant	593	-	593	98	319	158	18		
Working capital - gas	3,093	-	3,093					3,093	
Working capital - other	235	-	235	39	126	63	7		
Rate base	15,468	6,758	22,226	3,179	10,291	5,092	571	3,093	-
				14.3%	46.3%	22.9%	2.6%	13.9%	
Required return	1,132	390	1,522	218	705	349	40	212	
Income tax	131	(29)	102	15	47	23	3	14	
Property tax	80	37	117	32	28	49	8		
Depreciation (Depn allocated by gross plant)	882	269	1,151	313	277	481	79		
Hagar O&M - Fixed	1,463	263	1,726	286	928	459	52		
Hagar O&M - Variable	57	227	284						284
Admin O&M	1,353	-	1,353	225	728	360	41		
Compressor fuel	1,085	303	1,388						1,388
Revenue requirement	6,183	1,460	7,643	1,089	2,713	1,721	223	226	1,672
20% of Storage revenue requirement						344			
Liquefaction volume (GJ)	425,000	415,520	840,520	840,520	415,520	415,520			840,520
Revenue required per unit	14.548	3.513	9.093	1.296	6.529	0.828			1.989
LNG commercial business unit cost (Inventory cost not considered)				10.642	General liquefaction plus LNG dispensing plus Variable costs plus 20% of Storage				

To be read in conjunction with the accompanying letter dated July 17, 2014.

FORM A

Proceeding: EB-2014-0012

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Daniel Edwards (*name*). I live at ...TORONTO............(*city*), in the ....PROVINCE...........(*province/state*) of ...ONTARIO............. .

2. I have been engaged by or on behalf of NORTHEAST MIDSTREAM LP (*name of party/parties*) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date .....JULY..21/2014...

Daniel Edwards

Signature

6352189.1