unionGas
A Spectra Energy Company

May 16, 2014

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

Dear Ms. Walli:

Re: EB-2014-0012 – Union Gas Limited – Hagar Liquefaction Service Rate

Please find attached Union Gas Limited's ("Union") application and evidence seeking approval of rates for a new interruptible liquefaction natural gas service. This application is made pursuant to section 36 of the *Ontario Energy Board Act, 1998.*

This service, to be provided at Union's Liquefied Natural Gas ("LNG") facility at Hagar, Ontario, is in response to increasing interest in the use of natural gas and LNG particularly, as an economically and environmentally preferred fuel for heavy duty vehicles.

The Hagar facility is located in Union's Northern and Eastern operations area ("Union North") and is used to meet system integrity requirements. The new Rate L1 service will be facilitated using liquefaction capabilities that are excess to Union's system integrity requirements and will in no way impact Union's ability to meet these requirements. Union submits the new service will result in better utilization of Hagar and thus benefit ratepayers over its current Incentive Regulation Mechanism term by contributing to regulated earnings subject to sharing. On rebasing, the revenue from this service will form part of regulated revenue for ratemaking.

Union respectfully requests the Board initiate a written hearing process to review this application. It is Union's view the types of issues raised as part of this application can be addressed effectively through a written process.

Please contact me at (519) 436-5473 if you have any questions or wish to discuss this submission in more detail.

Yours truly,

[original signed by]

Karen Hockin
Manager, Regulatory Initiatives

c.c.: Charles Keizer, Torys
Mark Kitchen, Union Gas
EB-2013-0365 (2014 Rates) Intervenors

ONTARIO ENERGY BOARD

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 necessary to accommodate a new interruptible natural gas liquefaction service at its Hagar Liquefied Natural Gas facility.

APPLICATION

1. Union Gas Limited ("Union") is a business corporation, incorporated under the laws of Ontario, with its head office in the Municipality of Chatham-Kent.

2. Union conducts an integrated natural gas utility business that combines the operations of selling, distributing, transmitting and storing gas within the meaning of the *Ontario Energy Board Act, 1998* (the "Act").

3. Union hereby applies to the Ontario Energy Board ("Board"), pursuant to section 36(1) of the *Ontario Energy Board Act, 1998* (the "Act") for an order or orders approving a new interruptible natural gas liquefaction service. The service will be provided at Union's Liquefied Natural Gas ("LNG") facility Hagar, Ontario using liquefaction capacity that is excess to utility requirements.

4. This service is in direct response to an increased interest in the use of natural gas, and LNG particularly, as an economical and environmentally preferable fuel for heavy duty vehicles.

5. The service will allow Union, with the new facilities that it will construct adjacent to Hagar, to dispense LNG to LNG wholesalers or customers primarily for vehicle transportation fuel. Union plans to offer this service beginning September 1, 2015.

6. The service will result in better utilization of Hagar. This better utilization will benefit Union's ratepayers over the Incentive Regulation Mechanism ("IRM") term (2014-2018) by contributing to regulated earnings subject to sharing. On rebasing, the revenue from these services will form part of regulated revenue for ratemaking.

7. Specifically, Union applies to the Board for:

   (i) an order approving the proposed cost allocation methodology used to allocate 2013 Board-approved costs between liquefaction, storage and vapourization functions performed at Hagar;

   (ii) an order approving the proposed cost allocation methodology that allocates 2013 Board-approved Union North distribution costs to the Rate L1 service;

   (iii) an order approving a new Rate L1 rate schedule and a cost-based rate to accommodate an interruptible liquefaction service at Hagar;

   (iv) an order approving a maximum interruptible liquefaction rate on short-term (i.e. one year or less) liquefaction service equal to approximately three times the cost-based interruptible liquefaction rate;

   (v) an order approving modifications to the Union North Schedule "A" to accommodate Rate L1 gas supply charges expressed in dollars per gigajoules ($/GJ);

   (vi) for such interim order or orders approving interim rates or other charges and accounting orders as may from time to time appear appropriate or necessary; and

   (vii) all necessary orders and directions concerning pre-hearing and hearing procedures for the determination of this application.

8. This application will be supported by written evidence. This evidence will be pre-filed and will be amended from time to time as required by the Board, or as circumstances may require.

9. The persons affected by this application are the customers resident or located in the Municipalities, Police Villages and First Nations served by Union, together with those to whom Union sells gas, or on whose behalf Union distributes, transmits or stores gas. It is impractical to set out in this application the names and addresses of such persons because they are too numerous.

10. The address of service for Union is:

Union Gas Limited
P.O. Box 2001
50 Keil Drive North
Chatham, ON N7M 5M1

Attention: Karen Hockin
Manager, Regulatory Initiatives

Telephone: (519) 436-5473
Fax: (519) 436-4641

- and –

Torys LLP
Suite 3000, TD South Tower
P.O. Box 270
Toronto-Dominion Centre
Toronto, ON M5K 1N2

Attention: Charles Keizer

Telephone: (416) 865-7512
Fax: (416) 865-7380
email: ckeizer@torys.com

DATED: May 16, 2014

UNION GAS LIMITED

[Original signed by]

Karen Hockin
Manager, Regulatory Initiatives

Tab 1

HAGAR LIQUEFACTION SERVICE

The purpose of this evidence is to support Union Gas Limited's ("Union") application to the Ontario Energy Board ("Board") for approval of rates for a new interruptible natural gas liquefaction service. This service will be provided at Union's Liquefied Natural Gas ("LNG") facility at Hagar, Ontario using liquefaction capacity that is excess to utility requirements. The Hagar LNG facility is located in Union's Northern and Eastern operations area ("Union North") and currently is used to meet system integrity requirements.

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". The sale, transmission, distribution or storage of motor vehicle fuel gas by a person other than a Class A distributor is exempted from Section 36 of the OEB Act by Section 2. (2) (b) of O. Reg. 161/99. However, as liquefaction services at Union's Hagar facility will be provided within a regulated regime the use of the LNG could be expanded beyond motor vehicle fuel without further regulatory approvals. A detailed description of Union's cost allocation and rate design proposals for the above service is provided at Exhibit A, Tab 2.

Further, this new service will result in better utilization of Hagar. This better utilization will benefit Union's ratepayers over the Incentive Regulation Mechanism ("IRM") term (2014-2018) by contributing to regulated earnings subject to sharing. On rebasing, the revenue from this service will form part of regulated revenue for ratemaking.

The evidence is organized as follows:

1. Introduction
2. The Developing Market for LNG as a Vehicle Fuel
3. Current Hagar LNG Facility Operations
4. Excess Hagar Liquefaction Capabilities
5. Proposed Interruptible Liquefaction Service
6. Summary

1. Introduction

As indicated above, Union is seeking approval of an interruptible liquefaction service that will be provided from Hagar. This service will allow Union, with the new facilities that it will construct adjacent to Hagar, to dispense LNG to LNG wholesalers or customers. Specifically, Union is seeking approval of:

1. The proposed cost allocation methodology used to allocate 2013 Board-approved costs between liquefaction, storage and vapourization functions performed at Hagar;
2. The proposed cost allocation methodology that allocates 2013 Board-approved Union North distribution costs to the Rate L1 service;
3. A new Rate L1 rate schedule and a cost-based rate to accommodate an interruptible liquefaction service at Hagar;

4. A maximum interruptible liquefaction rate on short-term (i.e. one year or less) liquefaction service equal to approximately three times the cost-based interruptible liquefaction rate; and
5. Modifications to the Union North Schedule "A" to accommodate Rate L1 gas supply charges expressed in dollars per gigajoules ($/GJ).

The proposed service will be facilitated using liquefaction capabilities that are excess to Union's system integrity requirements. Offering this service will not impact, in any way, Union's ability to meet the utility's system integrity requirements.

Union is proposing the new service in response to increasing interest in the use of natural gas, and LNG particularly, as an economical and environmentally preferable fuel for heavy duty vehicles. Union will invest approximately $8.7 million in capital for incremental facilities and the related O&M to provide this new service. From September 1, 2015 to December 31, 2018, Union is forecasting approximately $8.5 million, or an average of $2.117 million per year, in utility revenue related to the provision of the liquefaction service. Table 1 summarizes the forecast activity, proposed rate, and utility revenues over the IRM term.

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.

2. The Developing Market For LNG as a Vehicle Fuel

Natural gas has a long history as a vehicle fuel in Ontario in the form of compressed natural gas ("CNG"). From 1984 to 2001, Union offered a Natural Gas for Vehicles ("NGV") service focused on expanding the use of CNG for all vehicle classes in Ontario. NGV was a regulated service offered to automobile refueling stations and fleet operators and was marketed as a more economical and environmentally friendly alternative to gasoline and diesel fuel for individual car owners and fleet operators. In 2002, Union discontinued the NGV service due to declining revenues and an inability to achieve the allowed return on investment. In Union's view NGV, as it was originally contemplated, was not successful for the following reasons:

1. To use NGV, vehicles had to be "converted" to burn natural gas. This included engine modifications and the addition of NGV cylinders. While incentives to convert were provided, they were insufficient to significantly stimulate market growth or economic support;
2. Original Equipment Manufacturers ("OEM") did not produce sufficient numbers of natural gas equipped vehicles for the Ontario market;
3. The NGV technology was not attractive to larger vehicle classes due to loss of power and torque as well as short-range travel distances between re-fueling;
4. The NGV re-fueling infrastructure did not develop to a sufficient level that would support or encourage vehicle conversion on a broader scale by the general public; and
5. Rising natural gas prices at the time relative to gasoline and diesel made NGV uneconomic.

In March, 2010, the Natural Gas Use in Transportation Roundtable, led by the Deputy Minister of Natural Resources Canada, was established. The Roundtable consisted of federal and provincial government officials, industry representatives, e.g. natural gas producers, transporters, distributors, vehicle makers, equipment manufacturers, and end users, as well as representatives from environmental non-governmental organizations and academia. *The Natural Gas Use in the Canadian Transportation Sector Deployment Roadmap* was the result of the Roundtable's work. This Roadmap has renewed interest in natural gas as a vehicle fuel for both CNG and LNG, and encourages a focus on larger vehicle classes operating in either a return to base daily cycle and/or point to point long haul transport fleets. As a result, LNG fuel for heavy duty vehicles has become an area of significant interest for the trucking industry, truck manufacturers and the energy sector. The interest in LNG as a vehicle fuel has increased for three reasons. First, the prospect of lower and more stable natural gas pricing over the long term favours LNG over diesel. Second, LNG as a truck fuel alternative to diesel is capable of delivering significant environmental benefits in the form of reduced carbon emissions. Third, LNG, unlike CNG, is able to meet the mileage expectations of long haul transport operators that are consistent with diesel.

Changes in North American Natural Gas Supply Dynamics

With the rapid development of shale formations, such as the Marcellus and the Utica shale, natural gas supplies in North America have increased dramatically. As a result of this abundance in natural gas supply, the price of natural gas is expected to remain low and stable over the long term relative to historical levels. At current natural gas prices, LNG is approximately 30% to 40% less costly than diesel on an energy equivalent basis.

Carbon Emissions Benefits

According to Natural Resources Canada, Energy Efficiency Trends in Canada, 1990 to 2009, the total energy consumed by heavy trucking (diesel) increased 164% from 1990 to 2009, the single largest increase of any sector in Canada. This increase also resulted in a corresponding increase in greenhouse gas emissions ("GHG") from heavy duty truck transportation of an equivalent percentage. New regulations[1] will limit the GHG emissions from all classes of vehicles, beginning in 2016.

GHG emissions can be reduced with natural gas versus both gasoline and diesel in all types of vehicles. For example, using Natural Resources Canada GHGenius model, version 3.15, total life cycle GHG emissions for a Class 8 transport tractor can be reduced from 1,365 g/km for diesel to 1,016 g/km for LNG, a 25.6% reduction.

According to the Canadian Vehicle Survey: Annual 2009, there were over 215,000 medium duty and heavy duty trucks operating in Ontario. Heavy duty vehicles in Ontario travelled over 8 billion km, consuming over 2.6 billion litres of diesel fuel and emitting 6.9 million tonnes of CO2. This amount of diesel is equivalent to 2.8 billion m^3 of natural gas. Based on these 2009 statistics, by substituting Ontario's heavy duty vehicle diesel fuel with LNG, Ontario's net CO2 emissions would be reduced by approximately 1.4 million tonnes.

<u>LNG as a Long Haul Fuel</u>

Heavy duty vehicles[2] include heavy tandem work trucks (i.e. cement, dump trucks etc.) and tractor trailer units, for both return to base and long haul operations. In return to base operations, trucks are typically required to travel shorter distances before refueling. In long haul operations, the transport operator's range expectations are in the order of 1,200 km per day.

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[1] Proposed amendments to the Canadian Environmental Protection Act, 1999 will limit GHG emissions from all classes of vehicles (light, medium and heavy duty) beginning in 2016 (2017 model year).

[2] On-road vehicle with a gross vehicle weight rating of more than 3,856 kg, a curb weight of more than 2,722 kg or a vehicle frontal area in excess of 4.2 m^2 (Heavy duty Vehicle and Engine Greenhouse Gas Emission Regulations SOR/2013-24, Canadian Environmental Protection Act, 1999)

To make natural gas viable as a transportation fuel, it must be “concentrated” either by compression or liquefaction due to the lower energy density of natural gas versus gasoline or diesel. CNG is natural gas that is compressed to as high as 3,600 psig and stored on board in specially designed cylinders. At this pressure, the volume of the natural gas is reduced by a factor up to 300 times relative to natural gas at normal pressure and temperature. For the standard vehicle configurations offered by manufacturers, expected range per fill is from 400 to 600 km, and is generally suited to return to base operations. In the case of LNG, the volume is reduced by a factor of up to 600 times relative to that of natural gas at normal pressure and temperature. This allows larger quantities of the fuel to be carried in the truck’s fuel cylinders. Using the same vehicle configuration as for the CNG example above, the expected mileage range is increased up to 1,200 km. This meets transport operator’s expectations for long haul service.

LNG and CNG in Other Jurisdictions

The renewed interest in CNG and LNG as a vehicle fuel is not isolated to Ontario. This market is actively being pursued in a number of other regulatory jurisdictions in both the United States and Canada.[3]

A FortisBC press release dated November 28, 2013 highlights key changes issued by the British Columbia government and the British Columbia Utilities Commission (“BCUC”) designed to “boost” the use of LNG as a transportation fuel. These changes include updates to the greenhouse gas reduction regulation as well as a direction that would exempt the planned

[3] Regie de l’energie decisions D-2010-144 (GMi 2011 Rate Case) and D-2011-030 (GMi) and BCUC Fortis BC Order (G-165-11A)

expansion of FortisBC's Tilbury LNG facility from a review by the BCUC. As stated in the release, these changes *"help increase FortisBC's ability to rapidly and cost-effectively supply liquefied natural gas (LNG) to the B.C. marketplace."* The release also noted that as part of the government's direction, the BCUC will set the LNG dispensing rate at $4.35/GJ. Schedule 1 is a copy of the release.

LNG as a transportation fuel in Quebec has gained support from both the government as well as Gaz Métro. For example, in a press release dated February 4, 2013, Gaz Métro highlights its LNG development plan. As stated in the release (see Schedule 2), the goal of its plan is two-fold: i) supply LNG to the heavy transport industry in Quebec and eastern Canada, through its indirect subsidiary Gaz Métro Transport Solutions, LP (GMTS), and; ii) assess the possibility of hauling LNG by truck to service more remote areas from Gaz Métro's natural gas pipeline network.

The government of Quebec has issued measures designed to support the use of natural gas for the freight transportation industry and heavy vehicles. As part of a program announced November 1, 2013, the government said it would subsidize 30% of the additional cost (up to a maximum of $75,000) for the purchase of vehicles running on natural gas (compressed and liquefied). The goal was to reduce GHG emissions in the transportation sector.

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

Determining the Market Interest for LNG

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.

Table 2 - Expressions of Interest

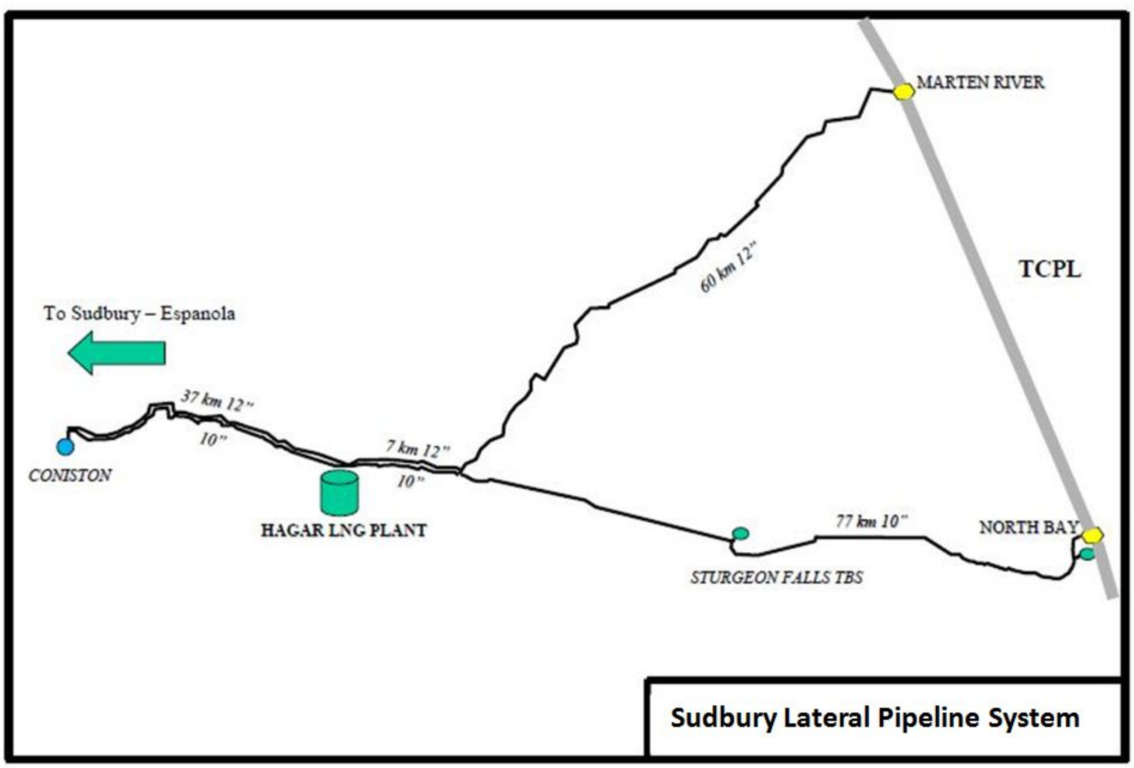
Party	Minimum Annual Commitment	Contract Term
"A"	106,180 GJ	Up to 5 years
"B"	55,000 to 165,000 GJ	3 to 5 years
"C"	90,253 GJ	5 years
"D"	150,000 GJ	10 years
"E"	190,000 GJ	Not Stated
"F"	109,200 GJ	Not Stated
Total	700,633 to 810,633 GJ	

The total of these volumes is within the actual LNG liquefaction capability that Union calculated to be surplus to its system integrity requirements. Union is currently in commercial negotiations with each of the interested parties and expects to have signed Precedent Agreements by the summer of 2014.

3. Current Hagar LNG Facility Operations

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. Figure 1 is a map showing the location of Hagar and the pipeline interconnections.

Figure 1
Hagar Plant and Interconnections



This facility serves system integrity requirements in Union North. As an integrated storage and transmission system operator Union requires system integrity space to support the integrity of the system as a whole and the provision of service to all customers. System integrity space provides reserve capacity and allows for the operational balancing necessary to manage all of the services Union offers and ensures the integrity of Union's storage, transmission and distribution systems. Hagar LNG is used to support the Sudbury Lateral during periods of higher than forecasted weather variations; supply shortfalls; and, unplanned pressure drops or outages. An example when Hagar's LNG was used for this purpose was on February 19, 2011 when a TransCanada pipeline experienced a pipeline rupture, fire and explosion near Beardmore, Ontario.

As a system integrity asset Hagar is operated to meet certain targets and parameters. The targets and parameters are:

1. A targeted full nominal capacity of 0.6 PJ in advance of the beginning of the peak winter season each year;
2. A daily vapourization[4] from the tank able to provide up to 90,000 GJ/d deliverability for injection into the Sudbury Lateral pipeline system; and
3. LNG balances in the tank, net of any withdrawals for system integrity purposes and boil off[5], are to remain available during the winter season, typically until the end of March.

The 2013 Board-approved revenue requirement for Hagar is approximately $6.2 million and is recovered from Union North customers in delivery rates.

[4] "vapourization" is the heating of the liquefied natural gas to convert it back to a gaseous state.
[5] "Boil off" is the process of evaporation that occurs unavoidably when natural gas is turned into LNG.

As indicated above, for Hagar to provide system integrity to Union North over the peak winter season, 0.6 PJ of LNG is required at Hagar in advance of the peak winter season. To meet this requirement natural gas arriving at Hagar is cooled to -162° C. When natural gas is cooled to this temperature, it condenses from a gas to a colourless and odourless liquid (LNG). The process for cooling natural gas is called liquefaction. The LNG is then pumped into the storage tank.

Once the tank is full, liquefaction is no longer required during the winter season. If necessary, Union is able to vapourize LNG at a rate that would fully deplete the tank in five to six days to meet a system integrity requirement. There have been no significant system integrity events that have resulted in the complete depletion of the tank.

4. Excess Hagar Liquefaction Capabilities

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 liquefaction that Union intends to market to its LNG customers.

Incremental Hagar Storage Space

Union proposes to increase the working storage space available at Hagar by upgrading the inventory measurement system from the current "tank-o-meter" measurement system to a radar measurement system. The existing "tank-o-meter" measurement system used to measure LNG inventory at Hagar was installed in 1968 and is accurate to +/- 0.97 ft of tank height. The tank-o-meter calculates the LNG storage tank fill height by using a pressure tube installed within the storage tank.

Union proposes to replace the current height measurement equipment with a radar measurement 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.

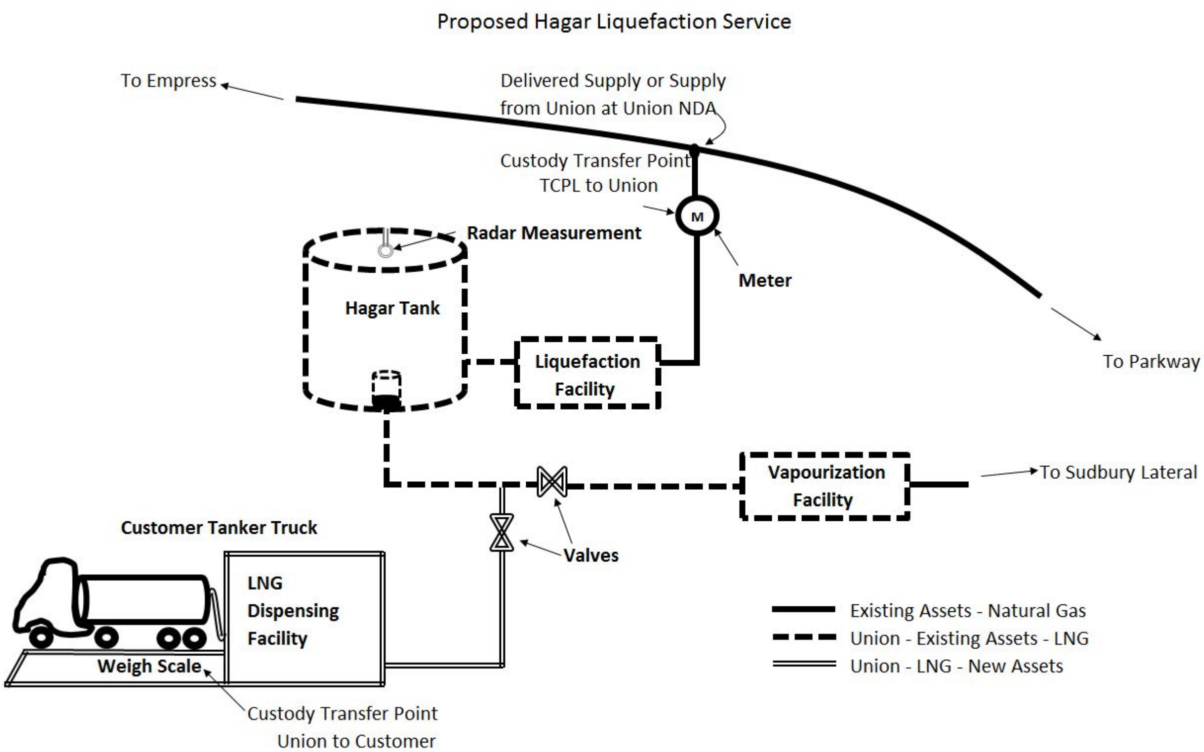
Union proposes to recover the $200,000 capital cost as part of the liquefaction rate. Union will utilize the incremental LNG storage space to manage differences between natural gas deliveries for liquefaction and quantities of LNG dispensed. The space will allow Union to continue to dispense LNG to its customers during Hagar liquefaction equipment maintenance periods. To ensure there is no significant accumulation of stored gas, the deliveries and takings will be managed contractually. Any storage required is temporary and the result of timing differences.

5. Proposed Interruptible Liquefaction Service

Union is proposing to provide an interruptible liquefaction service. This service will be provided under the new Rate L1 rate schedule. Included in this service is the option for Union to provide the customer an accompanying natural gas supply service and natural gas transportation service to Union’s NDA. The natural gas supply service and transportation service will be provided under the proposed changes to new and existing Board approved rate schedules; proposed Rate L1 and Union North Schedule “A”. The cost allocation and rate design for these new services is described in more detail in Exhibit A, Tab 2.

Figure 2 provides a schematic of the Hagar facilities, services and the proposed natural gas flows from Union's NDA to the LNG dispensing facility at Hagar.

Figure 2



As shown in Figure 2, natural gas will be delivered to the Union NDA. The natural gas delivered to Union NDA will either be purchased under a Board-approved rate schedule from Union or the customer may choose to source its own natural gas supply and arrange to have it transported to the Union NDA. Irrespective of the upstream transportation and gas supply arrangement, the natural gas delivered to the Union NDA will be transported to Hagar as part of the Rate L1 liquefaction service.

Once delivered to Hagar, the gas will be liquefied and pumped into the LNG tank on behalf of the customer where it will be stored and ultimately pumped to the dispensing facility.

Gas Supply Commodity and Upstream Transportation Arrangements

There are two options available for customers to manage their gas supply commodity and upstream transportation arrangements. The first option is for the customer to contract with Union for the provision of utility sales service under the proposed L1 rate schedule and the Union North Schedule “A”. Under this option, Union would provide both gas supply commodity and upstream transportation.

The second option is for the customer to contract directly with gas suppliers or marketers for the provision of gas supply commodity and upstream transportation to deliver natural gas to the Union NDA. Under this option, the customer will manage its own gas supply and upstream transportation arrangements in a manner similar to other Union North direct purchase (transportation service) customers.

At this time, it is Union’s expectation that most customers will contract for utility sales service under the proposed L1 rate schedule and Union North Schedule “A”. As described above, Union is proposing modifications to Union North Schedule “A” to accommodate gas supply charges in dollars per gigajoule ($/GJ) in order to charge customers for this service.

New Hagar Interruptible Liquefaction Service

The new Hagar interruptible liquefaction service incorporates the distribution service from the Union NDA to the Hagar facility as well as the liquefaction of the natural gas, the dispensing of the LNG to tankers and any temporary storage of the LNG due to timing differences between natural gas being liquefied and ultimately dispensed. All gas delivered to Hagar on behalf of the customer will be liquefied and pumped into the tank. During periods of maintenance or if the utility requires the liquefaction capability in order to refill the tank to 0.6 PJs, the liquefaction service may be curtailed in whole or in part. The liquefaction service must be interruptible to ensure that Hagar is able to meet its system integrity requirements.

Union proposes to allocate a storage space entitlement of 7,000 GJs in aggregate to accommodate this service within the main Hagar storage tank. As described above, Union’s ability to use this space is a result of the installation of a new radar measurement system which 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.

Customer Forecast and Minimum Annual Volumes

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).

Incremental Capital Cost

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.

Table 3
Total Estimated Project Capital Costs ($ millions)

Prime Contractor	4.100
Company Materials	
(Valves/piping, pumping skid, control building, radar measurement)	2.200
Company Expenses and Labour	0.180
Outside Services	
(3rd party design, inspection, x-ray, survey)	0.720
Contingencies & IDC	1.500
Total Project Cost	**8.700**

Incremental O&M Expenses

Union is forecasting total incremental O&M expenses of $1.072 million per year by 2018. These incremental O&M expenses are driven by the increased usage of the liquefaction equipment at Hagar associated with the provision of the proposed liquefaction service. Table 4 provides a detailed breakdown of the forecasted incremental O&M expenses from September 2015 to December 2018.

Table 4
Incremental Hagar LNG Liquefaction and Storage O&M Costs ($000's)

Line No.	Particulars	2015	2016	2017	2018
		(a)	(b)	(c)	(d)
1	Salary and Wages	34	103	207	207
	Maintenance Expenses				
2	Contractor Expenses	5	27	45	53
3	Technician Expenses	8	39	66	77
4	Road Upgrade	500	-	-	-
5	Total Maintenance Expenses	513	65	111	131
	Operating Expenses				
6	Materials	18	91	154	181
7	Electricity	6	29	50	58
8	Compressor Fuel	49	247	421	495
9	Total Operating Expenses	73	367	624	734
10	Total Incremental O&M	621	536	942	1,072

The Hagar facility has one manager, one supervisor, one administration staff and eight operators. As a result of the new service, Union estimates that it requires one additional operator at the plant in 2015 and 2016 and two additional operators in 2017 through 2018 to safely liquefy and comply with TSSA requirements. The staffing requirements assume up to 213 days of incremental liquefaction based on the liquefaction forecast provided at Exhibit A, Tab 2, Schedule 5. Based on the addition of one to two roles required to liquefy, Union estimates the incremental employee-related costs are approximately $34,000 for four months in 2015 to $207,000 per year by 2017. The employee-related costs include base salary, employee benefits and employee expenses.

Union is also forecasting incremental costs associated with maintaining the liquefaction equipment at the plant. Based on the liquefaction forecast, Union estimates incremental maintenance costs of $131,000 per year by 2018, which include incremental costs for the Union Gas technicians and external contractors. Union also is forecasting $500,000 in 2015 for a one-time upgrade to the municipal road entering the Hagar LNG facility. The road upgrade is required to provide LNG tanker trucks access to the facility.

Union is also forecasting incremental material, electricity and compressor fuel costs associated with the increased operation of the Hagar LNG facility. These incremental operating costs directly relate to the operation of the liquefaction equipment at the plant and vary directly with the volume of liquefied gas produced. Based on the liquefaction forecast, Union estimates incremental material costs of $181,000 per year by 2018, which include the costs for refrigerants, compressor parts and various other consumables. Union also estimates incremental electricity costs of $58,000 and compressor fuel costs of $495,000 per year by 2018.

6. Summary

In summary, Union is seeking approval of an interruptible liquefaction service that will be provided at Hagar. This service will allow Union, with the new facilities that it will construct adjacent to Hagar, to dispense LNG to LNG wholesalers for vehicle fuel. Union proposes to start construction in May 2015 with a target in-service date of September 1, 2015.

Specifically, Union is seeking approval of:

1. The proposed cost allocation methodology used to allocate 2013 Board-approved costs between liquefaction, storage and vapourization functions performed at Hagar;
2. The proposed cost allocation methodology that allocates 2013 Board-approved Union North distribution costs to the Rate L1 service;
3. A new Rate L1 rate schedule and a cost-based rate to accommodate an interruptible liquefaction service at Hagar;
4. A maximum interruptible liquefaction rate on short-term (i.e. one year or less) liquefaction service equal to approximately three times the cost-based interruptible liquefaction rate; and
5. Modifications to the Union North Schedule "A" to accommodate Rate L1 gas supply charges expressed in dollars per gigajoules ($/GJ).

A detailed description of Union's cost allocation and rate design proposals related to these services is provided at Exhibit A, Tab 2.

The proposed services will be facilitated using liquefaction capabilities that are excess to Union's system integrity requirements. Offering this service will not impact, in any way, Union's ability to meet the utility's system integrity requirements.

Union is proposing this new service in response to increasing interest in the use of natural gas, and LNG particularly, as an economical and environmentally preferable fuel for heavy duty vehicles. From September 1, 2015 to December 31, 2018, Union is forecasting approximately $8.5 million, or an average of $2.117 million per year, in utility revenue related to the provision of liquefaction services.

These new services will result in better utilization of Hagar. This better utilization will benefit ratepayers over the Incentive Regulation Mechanism ("IRM") term (2014-2018) by contributing to regulated earnings subject to sharing. On rebasing, the revenue from these services will form part of regulated revenue for ratemaking.

SCHEDULES

Filed: 2014-05-16
EB-2014-0012
Tab 1
Schedule 1

Tilbury LNG Facility expansion and natural gas for transportation boosted by government announcement

November 28, 2013

FortisBC transportation and natural gas customers benefit from changes

SURREY, BC – FortisBC, a subsidiary of Fortis Inc. (TSX: FTS) commends the B.C. government for changes announced today that will help to increase FortisBC's ability to rapidly and cost-effectively supply liquefied natural gas (LNG) to the B.C. marketplace.

The changes include updates to the greenhouse gas reduction regulation and directions to the BC Utilities Commission (BCUC), including the exemption of the planned expansion of FortisBC's Tilbury LNG facility from a certificate of public convenience and necessity review by the BCUC.

"Today's direction from government allows FortisBC to better support the province in the development of natural gas for the transportation sector. This announcement will also result in increased LNG supply, creating opportunities for industrial users and remote communities, bringing economic development and new jobs to B.C." said John Walker, president and CEO of FortisBC.

"Government's announcement, also positions FortisBC to move forward immediately with plans to expand our Tilbury LNG Facility. This project contemplates an investment of up to $400 million," said Walker.

The investment in the FortisBC Energy Inc. gas utility would be subject to FortisBC Board approval and additional regulatory and environmental permits and approvals, including the B.C. Oil and Gas Commission. The expansion is expected to include a second tank and a new liquefier, both to be in service by mid-2016. The expansion will add approximately one million gigajoules of LNG storage, as well as 30,000 to 60,000 gigajoules of liquefaction capacity per day. It will also provide 300 person-years of construction jobs and about $4 million a year in taxes paid to various levels of government over time. FortisBC expects to finance the expansion as part of its natural gas regulated rate base.

"Government wanted to get out of the way and allow the transportation fuel component of the LNG industry develop quickly," said Bill Bennett, minister of energy and mines and minister responsible for core review. "This $400-million investment in FortisBC's Tilbury LNG Facility will build B.C.'s marketplace for the world's cleanest fuel, LNG, and create over 300 person-years of employment in the Lower Mainland."

As part of government's direction, the BCUC will set the LNG dispensing rate at $4.35/gigajoule. This will help the transportation sector transition to adopt LNG as a fuel source and allow Northern and remote communities to switch to LNG, away from fuels like diesel.

Today the government also announced changes to its greenhouse gas reduction regulation. Key changes to benefit FortisBC customers include:

- an increase to the allowed capital per station for building LNG or compressed natural gas (CNG) fuelling stations that will meet the needs of customers with larger fleets;
- an increase in the incentive funding for safety training and upgrades to LNG or CNG vehicle maintenance facilities; and
- the expansion of incentives to rail and mining vehicles.

FortisBC expects that its gas utility customers will benefit from the additional volumes moving through the pipeline system to serve the expanded LNG facility. Better year-round, utilization of FortisBC's infrastructure, especially during the summer months when heating requirements are reduced, helps to keep natural gas delivery rates stable.

Media Backgrounder

Tilbury LNG Facility

LNG is natural gas that has been cooled to a low temperature of -162°C to become a liquid.

FortisBC uses LNG to supplement gas supply during periods of peak demand as well as for transportation customers. In operation since 1971, our LNG facility on Tilbury Island in Delta, B.C. is located near the FortisBC transmission pipeline system just a few kilometres from metropolitan Vancouver.

From the Tilbury LNG Facility, LNG is delivered by tanker truck to the LNG dispensing station on a customer's property or at a commercial fuelling station along a regional corridor.

- The current Tilbury LNG Facility can liquefy 5,000 gigajoules of natural gas per day.
- Since LNG takes up 1/600th of the volume of gas, the tank, with a volume of 28,000 cubic metres, holds the equivalent of 17 million cubic metres (600,000 gigajoules) of natural gas — enough gas to keep a community of 12,000 warm for about 45 very cold days.

LNG dispensing rate

The LNG dispensing rate has been set at $4.35/gigajoule. This is intended to cover the cost of the transportation of the gas to the facility, liquefaction and dispensing. Customers will also pay the natural gas commodity cost per gigajoule.

Environmental benefits of natural gas for transportation

Converting fleets and vehicles to natural gas not only helps the province meet its greenhouse gas reduction goals but also helps improve air quality in the communities in which they serve.

- Natural gas burns cleaner than gasoline or diesel, which can result in less pollution and greenhouse gases.
- Carbon dioxide (CO2) emissions, the principal greenhouse gas that contributes to global warming, are reduced by 20 to 30 per cent.
- Natural gas vehicles emit virtually no particulate matter, the harmful microscopic component of air pollution that penetrates deeply into the lungs.
- Businesses converting their fleet to natural gas will help meet the province's requirements for greenhouse gas reductions under the B.C. Greenhouse Gas Reduction Targets Act.
- Natural gas for transportation also helps achieve B.C.'s energy objectives defined under the Clean Energy Act.

Other benefits

- **More stable fuel costs:** historically, natural gas commodity prices have been shown to be more stable, compared to the fluctuation of prices for diesel and gasoline. Natural gas fuel costs have historically been 25 to 40 per cent less than diesel.
- **Fewer emissions:** natural gas is a cleaner burning, lower carbon fuel than diesel or gasoline.
- **Quieter:** operators of natural gas waste hauler trucks report they are quieter than comparable diesel trucks.

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"expects," "intend" “contemplate” and similar expressions have been used to identify the forward-looking statements. The forward looking statements in this media release include, but are not limited to, statements regarding: increased supply of LNG; job creation; taxes and the size of the investment in Tilbury Facility. These statements reflect management's current beliefs and are based on information currently available to the Company's management. Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking statements, which include but are not limited to receipt of applicable regulatory approvals and requested rate orders; absence of equipment breakdown, absence of environmental damage and health and safety issues, absence of adverse weather decisions and natural disasters, no significant operational disruptions or environmental liability as a result of a catastrophic event or environmental upset ability to obtain and maintain applicable permits, the adequacy of the corporation’s existing insurance arrangements, the First Nations settlement process does not adversely affect the corporation, the ability to maintain and renew collective bargaining agreements on acceptable terms, the ability to arrange sufficient and cost effective financing, no material adverse ratings actions by credit rating agencies, the competitiveness of natural gas pricing when compared with alternate sources of energy; continued population growth and new housing starts; the availability of natural gas supply; access to capital; interest rates and the ability to hedge certain risks. These factors or assumptions are subject to inherent risks and uncertainties surrounding future expectations generally that could cause actual results to differ materially from historical results or results anticipated by the forward-looking statements. Such risk factors include, but are not limited to, regulatory approval and rate orders risk; operational disruptions and environmental risk; price competitiveness risk; changes in economic conditions; natural gas supply risks; capital and credit ratings risk, interest rate risk and counterparty credit risk. These factors should be considered carefully and undue reliance should not be placed on the forward-looking statements. For additional information with respect to certain of these risks or factors, reference should be made to the Company's Management Discussion & Analysis.

Press Releases

Filed: 2014-05-16
EB-2014-0012
Tab 1
Schedule 2

print

Gaz Métro relies on the use of liquefied natural gas in the heavy transportation sector

Natural gas: An economical and environmental alternative to traditional fuels

Montréal, February 4, 2013 - Gaz Métro is proud to take stock of its achievements in line with its liquefied natural gas (LNG) development plan. The goal of this plan is to supply LNG to the heavy transport industry in Quebec and eastern Canada, via its indirect subsidiary Gaz Métro Transport Solutions, LP (GMTS), and subsequently to assess the possibility of hauling LNG by truck to service more remote areas from Gaz Métro's natural gas pipeline network.

Accordingly, GMTS has been working with a number of partners and road transportation companies since 2010 to ensure that local carriers can enjoy the significant economic and environmental advantages of LNG, compared with diesel fuel. GMTS is playing a pivotal role as an expert and leader in the planning and implementation of initiatives designed to develop LNG-powered fleets. In addition, GMTS owns and operates two private fuelling stations in Quebec, on Robert Transport sites: one on the South Shore of Montreal and the other (a mobile unit) in the Quebec City area. It also owns and operates a third fuelling station in the Mississauga area.

Achievements and current projects

In the heavy transportation sector, as a result of infrastructure investments made by GMTS (fuelling stations):

- Transport Robert 1973 Ltd. (Robert Transport) plans to have 130 LNG-powered trucks (out of a total 180 trucks ordered) on the road by early summer 2013.
- Transport YN.-Gonthier Inc. introduced its first two LNG trucks in October 2012.
- A first for eastern Canada: Camions Excellence Peterbilt Inc. now has one LNG-fuelled truck available for short-term rentals.

In the marine transportation sector:

The Société des traversiers du Québec (STQ) has announced the purchase of three LNG-powered ferries, which will be able to procure natural gas through GMTS:

- One ferry for the Matane-Baie-Comeau-Godbout crossing
- Two ferries for the Tadoussac-Baie-Sainte-Catherine crossing.

In the rail transportation sector:

GMTS is supplying LNG as part of a project to develop an LNG-powered locomotive, in collaboration with Westport Innovations, CN and Electro-Motive Diesel, Inc. (EMD).

Projects in development

GMTS is in talks with several carriers interested in ordering LNG trucks in the coming months.
A series of public fuelling stations will be set up along highways 20 and 401 to strengthen and

complement the existing private network. This public network may also eventually merge with the North American network, thereby enabling carriers to provide continent-wide coverage using natural gas-fuelled vehicles. The first step will entail setting up public stations in Rivière-du-Loup, Lévis and Cornwall, which are expected to be operational by the end of 2013. Two mobile fuelling stations have been ordered to accelerate the process. During the second phase, two additional public stations will be incorporated into the network: one east of Toronto and the other south of Montreal.

Catering to the increased demand for LNG

Given the projected rapid growth in market demand for LNG, specifically from the perspective of GMTS to which Gaz Métro provides liquefaction services, Gaz Métro is currently looking into several solutions for improving the availability of LNG in Quebec, including increasing liquefaction output, either by itself or via a subsidiary, directly through its liquefaction, storage and regasification (LSR) plant. This would be contingent on the findings of the requisite financial studies in terms of project feasibility and, eventually, on the outcome of the appropriate regulatory processes. The LSR plant, which supplies Gaz Métro customers during peak periods, is located in the east end of Montreal and has been operating for more than 40 years. As the present storage capacity of the two existing reservoirs easily meets current customer demand, Gaz Métro is now working on the front-end engineering design (FEED) for a project focusing solely on increasing liquefaction capacity to accommodate LNG needs. This should be finalized by the end of March. Following this, provided that major contractual agreements are signed with such clients as GMTS, a request for proposals may follow in April for the engineering, procurement and construction (EPC) of an additional liquefaction unit.

The environmental advantage of natural gas

The transport industry is Quebec's leading producer of greenhouse gas (GHG) emissions. In 2009, it accounted for 43.5% of the total emissions generated. Road freight transportation via heavy diesel vehicles is responsible for 30.3% of this figure, making it a key target for GHG reduction efforts. Natural gas, which emits up to 25% less GHG emissions than diesel, is the alternative of choice.

The economic advantage of natural gas

Fuel represents one of the transportation industry's biggest expenses, and the cost of natural gas can be up to 40% less than diesel. By using natural gas to meet their fuel needs, companies can reduce their operating expenses at the same time as they improve their environmental footprint.

About Gaz Métro Transport Solutions
Gaz Métro Transport Solutions (GMTS) is an indirect subsidiary of Gaz Métro, Quebec's leading natural gas distributor. GMTS was created to encourage the transportation industry to switch to natural gas, the only available alternative to diesel. GMTS is committed to developing a market in Quebec for compressed and liquefied natural gas as a source of fuel. Natural gas is a more economical choice and generates less greenhouse gas emissions than diesel. It therefore has enormous potential for the transportation industry from a commercial standpoint. www.gazmetrost.com

About Gaz Métro
With over $5 billion in assets, Gaz Métro is a leading energy provider. It is the largest natural gas distribution company in Quebec, where its 10,000-km underground network of pipelines serves 300 municipalities and more than 185,000 customers. Gaz Métro is also present in Vermont, producing electricity and distributing electricity and natural gas to cater to the needs to some 300,000 customers. Gaz Métro is actively involved in the development of innovative, sustainability-oriented energy projects such as the production of wind power, the use of natural gas as a transportation fuel and the development of biomethane as a renewable energy source. Gaz Métro is committed to ensuring the satisfaction of its customers, providing support to businesses, local organizations, families and communities, and meeting the needs of its partners (Gaz Métro inc. and Valener) and employees. www.gazmetro.com

Cautionary note regarding forward-looking statements
This press release may contain forward-looking information within the meaning of applicable securities laws. Such forward-looking information reflects the intentions, plans, expectations and opinions of the management of GMi, in its capacity as General Partner of Gaz Métro, and acting as manager of Valener (the management of the manager) and is based on information currently available to the management of the manager and assumptions about future events. Forward-looking statements can often be identified by words such as "plans," "expects," "estimates," "forecasts," "intends," "anticipates" or "believes" or similar expressions, including the negative and conjugated forms of these words. Forward-looking statements

involve known and unknown risks and uncertainties and other factors beyond the control of the management of the manager. A number of factors could cause the actual results of Valener or of Gaz Métro to differ significantly from current expectations, as described in the forward-looking statements, including but not limited to the general nature of the aforementioned, terms of decisions rendered by regulatory agencies, the competitiveness of natural gas in relation to other energy sources, the reliability of natural gas and electricity supply, the integrity of the natural gas and electricity distribution systems, the ability to complete attractive acquisitions and the related financing and integration aspects, the ability to secure future financing, general economic conditions, exchange rate and interest rate fluctuations, weather conditions and other factors described in the Risk Factors Relating to Valener and the Risk Factors Relating to Gaz Métro sections of Valener's and Gaz Metro's MD&As for the year ended September 30, 2012 and in Valener's disclosure filings. Although the forward-looking statements contained herein are based on what the management of the manager believes to be reasonable assumptions, including assumptions to the effect that no unforeseen changes in the legislative and regulatory framework of energy markets in Quebec and in the New England states will occur; that the applications filed with the Régie, in particular the rate applications and the authorized return on deemed equity application will be granted as filed; that natural gas prices will remain competitive; and that no significant event occurring outside the ordinary course of business, such as a natural disaster or other calamity, will occur; in addition to the other assumptions described in the Valener and Gaz Métro MD&As for the quarter ended December 31, 2012, the management of the manager cannot assure investors that actual results will be consistent with these forward-looking statements. These forward-looking statements are made as of this date, and the management of the manager assumes no obligation to update or revise them to reflect new events or circumstances, except as required pursuant to applicable securities laws. Readers are cautioned to not place undue reliance on these forward-looking statements.

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TAB 2

HAGAR LIQUEFACTION SERVICE - COST ALLOCATION AND RATE DESIGN

The purpose of this evidence is to support Union's request for approval of (i) a cost allocation methodology that allocates 2013 Board-approved Hagar costs between the liquefaction, storage and vapourization functions performed at Hagar, (ii) a cost allocation methodology that allocates 2013 Board-approved Union North distribution costs to the Rate L1 service (iii) a new Rate L1 rate schedule and rates to accommodate an interruptible liquefaction service at the Hagar facility and (iv) modifications to the Union North Schedule "A" to accommodate Rate L1 gas supply charges expressed in dollars per gigajoules ($/GJ).

Introduction

Union's 2013 Board-approved cost allocation study does not functionalize the costs at the Hagar facility between the liquefaction, storage and vapourization functions. For the purposes of designing an interruptible liquefaction rate, Union must determine the 2013 Board-approved costs at Hagar associated with the liquefaction and storage functions. Accordingly, Union is proposing a cost allocation methodology that allocates costs amongst the three functions performed at Hagar.

To determine the allocation of 2013 Board-approved Hagar costs by function, Union engaged KPMG to conduct a comprehensive cost allocation review of current approved rate base-related, operating and maintenance and compressor fuel costs at Hagar and recommend a cost allocation methodology. Union has adopted the proposed cost allocation methodology recommended by KPMG, which is described in more detail below.

Union is also seeking approval of a Union North distribution cost allocation methodology to recognize the Rate L1 customers' use of the distribution system required to transport gas from the TCPL interconnect locations to the Hagar LNG facility. Union is proposing to use the same cost allocation methodology that was previously approved by the Board in EBRO 484 for the Rate 77 wholesale transportation service.

Union is also proposing to introduce a new Rate L1 rate schedule and a cost-based interruptible liquefaction rate. The cost-based interruptible liquefaction rate is intended to make a contribution towards the recovery of existing Hagar liquefaction and storage costs, Union North distribution costs, and to recover the incremental costs associated with the provision of the interruptible liquefaction service. Union also proposes a maximum interruptible liquefaction rate on short-term (i.e. one year or less) liquefaction service equal to approximately three times the cost-based interruptible liquefaction rate. The maximum interruptible liquefaction rate will enable Union to respond to the potential market value of its short-term interruptible liquefaction service.

Finally, Union is proposing to modify the Union North Schedule "A" to accommodate Rate L1 minimum and maximum gas supply charges expressed in $/GJ. The Rate L1 minimum and maximum gas supply charges are based on Board-approved Rate 25 gas supply charges. These modifications will enable Union to invoice the Rate L1 gas supply service in energy, consistent with the invoicing of the proposed interruptible liquefaction rate.

This evidence is organized as follows:

1. 2013 Board-Approved Hagar Revenue Requirement and Cost Allocation Methodology
2. Proposed Allocation of 2013 Board-Approved Hagar Costs by Function
3. Distribution Cost Allocation Methodology
4. Rate Design and Rate Schedule Changes

1. 2013 Board-Approved Hagar Revenue Requirement and Cost Allocation Methodology

Per Union's 2013 Board-approved cost allocation study, the current approved revenue requirement associated with the Hagar facility is approximately $6.2 million. This revenue requirement includes rate base-related costs, operating and maintenance expenses and compressor fuel. Excluding compressor fuel costs of approximately $1.1 million, the current approved revenue requirement for the Hagar facility is approximately $5.1 million.

The rate base-related costs include the return on Hagar rate base, income taxes, property taxes and depreciation expense. The Hagar rate base includes Hagar net plant, an allocation of general plant and working capital. The operating and maintenance and compressor fuel costs include direct assigned costs specific to the operation of the Hagar facility and an allocation of indirect administrative and general costs.

Please see Table 1 below for a summary of the 2013 Board-approved Hagar rate base and revenue requirement.

Table 1
2013 Board-Approved Hagar Rate Base and Revenue Requirement

Line No.	Particulars	Revenue Requirement ($000's)
	Rate Base	
1	Hagar Net Plant	11,547
2	General Net Plant	593
3	Gas In Storage Working Capital	3,093
4	Other Working Capital	235
5	Rate Base	15,469
	Revenue Requirement	
6	Return on Rate Base	1,132
7	Property and Income Taxes	212
8	Depreciation Expense	882
9	Hagar O&M Expenses	1,520
10	Administrative and General Expenses	1,353
11	Compressor Fuel	1,085
12	Total Revenue Requirement	6,183
13	Total Revenue Requirement Excluding Compressor Fuel (line 12 - line 11)	5,098

In accordance with Board-approved methodology, Union classified $5.1 million of Hagar costs to the storage system integrity function to recognize that the Hagar facility provides system integrity to firm Union North in-franchise customers. The $5.1 million of Hagar system integrity costs were allocated to Union North rate classes in proportion to the excess of peak day demand over average day demand.

The Hagar compressor fuel costs of $1.1 million were classified as a storage commodity-related cost and allocated to firm Union North rate classes in proportion to sales service and direct purchase winter volumes.

The 2013 Board-approved costs associated with the Hagar facility are recovered from firm Union North in-franchise customers in delivery rates.

2. Proposed Allocation of the 2013 Board-Approved Hagar Costs by Function

As described above, Union engaged KPMG to conduct a comprehensive cost allocation review of 2013 Board-approved Hagar costs and recommend a cost allocation methodology that functionalizes these costs between liquefaction, storage and vapourization functions. Union has adopted the proposed cost allocation methodology recommended by KPMG.

In summary, Union is proposing to directly assign 2013 Board-approved Hagar costs to a liquefaction, storage or vapourization function where Union can specifically identify the cost as being directly attributable to that function. For 2013 Board-approved Hagar costs that support the overall operations of the Hagar facility and cannot be directly attributed to a particular function, Union is proposing to functionalize those costs in proportion to the functionalization of directly assigned costs.

Please see Schedule 1 for a detailed breakdown of the 2013 Board-approved Hagar revenue requirement by function.

In the following sections, Union has provided a description of the comprehensive cost allocation review and proposed cost allocation methodology used to determine the allocation by function of a) Hagar facility assets, b) operating and maintenance expenses and c) indirect costs and taxes. Please also see Attachment A for the final KPMG report.

a. Hagar Facility Assets

The first step in the cost allocation review was to determine the function of the individual assets at the Hagar facility. Through this process, Union and KPMG reviewed the assets at Hagar and identified which Hagar assets were directly attributable to the provision of liquefaction, storage or vapourization. Assets that were directly attributable to one of these functions were directly assigned to that function. For example, if an asset at the Hagar facility was determined to be required to liquefy natural gas only, the asset was directly assigned to the liquefaction function.

As Union maintains separate plant accounting records for Hagar, Union and KPMG were able to directly assign the net plant and depreciation expense of the assets that are used for liquefaction only to the liquefaction function. Union was also able to directly assign the net plant and depreciation expense for the assets that are used for storage or vapourization only to the storage and vapourization functions, respectively.

Where an asset at the Hagar facility was determined to support the overall operations of the facility, rather than a specific function, the asset was functionalized in proportion to the directly assigned assets.

Accordingly, Union direct assigned $5.807 million (or approximately 50%) of the total $11.547 million in Hagar net plant, as shown in Table 2, line 1. The remaining net plant of $5.740 million was functionalized in proportion to the direct assigned assets, as shown in Table 2, line 2.

Table 2
2013 Hagar Net Plant by Function

Line No.	Particulars ($000's)	Liquefaction (a)	Storage (b)	Vapourization (c)	Total (d)
1	Direct Assigned Net Plant	2,089	3,344	374	5,807
2	Remaining Net Plant (1)	2,065	3,305	370	5,740
3	Total Net Plant	4,155	6,649	743	11,547
4	Total Net Plant (%)	36%	58%	6%	100%

Note:
(1) Functionalized in proportion to the directly assigned net plant (line 1).

The derivation of the direct assignments for the Hagar assets and the allocation of the remaining net plant are described below.

Hagar Assets that Provide Liquefaction Only

Union and KPMG have identified assets at the Hagar facility that are used solely for the provision of liquefaction.

The Hagar assets that are required to liquefy natural gas include the assets associated with purifying, cooling and recovering boil off gas. To purify gas at the Hagar facility, gas passes through a purification process, which involves a system of molecular sieves that remove residual oil, moisture, sulphur and odourant from the gas stream. To clean the molecular sieves, the gas is heated through a salt bath heater. To cool and liquefy the gas, gas enters into the refrigeration system, known as the cold box, and the main cycle compressor provides the energy requirements for the refrigeration system. To recover the boil off gas, one of the two boil off compressors recovers the boil off gas that is formed during the liquefaction process.

As these assets are used solely to provide liquefaction, Union has direct assigned the costs associated with the salt bath heater, molecular sieve beds, cold box, the cooling towers, the cycle gas compressor and the boil off compressor to the liquefaction function. Of the total $11.547 million in net plant at the Hagar facility, $2.089 million is directly attributable to the liquefaction function (Table 2, line 1, column (a)).

Hagar Assets that Provide Storage Only

Union and KPMG have also identified assets at the Hagar facility that are used solely for the provision of storage.

The Hagar assets that are used solely for storage include the storage tank and a second boil-off compressor at the Hagar facility. The second boil off compressor is used exclusively to recover the boil off gas that is formed during storage.

Of the total $11.547 million in net plant at the Hagar facility, $3.344 million is directly attributable to storage (Table 2, line 1, column (b)).

There is also $3.093 million in rate base for gas in storage working capital that is directly attributable to the storage function, for system integrity purposes only (Table 1, line 3). The 2013 Board-approved revenue requirement associated with the gas in storage working capital includes a return on gas in storage of $0.226 million and $0.026 million in income taxes. The total revenue requirement of $0.253 million associated with the $3.093 million in rate base for gas in storage working capital has also been functionalized to storage.

Notwithstanding the functionalization of gas in storage working capital to the storage function, Union's proposed liquefaction rate is not designed to make a contribution to the recovery of the

2013 Board-approved revenue requirement for gas in storage working capital. Union's proposed liquefaction rate design is described in further detail in Section 3 below.

Hagar Assets that Provide Vapourization Only

Union and KPMG have also identified assets at the Hagar facility that are used solely for the provision of vapourization and are not required in the provision of liquefaction or storage.

The Hagar assets that are used solely for vapourization include the LNG pump, which is used to pump the liquefied natural gas from the storage tank and the vapourizer assets, which are used to heat the liquefied natural gas and convert it back to a gaseous state.

Also included in this category are Solar gas turbine driven compressors that are located at Hagar. These compressors are used to increase the pressure on the distribution lines to serve the Sudbury-Espanola areas. These solar compressor units are fully depreciated and for the purposes of asset categorization, the residual value was included with the assets that solely provide vapourization.

Of the total $11.547 million in net plant at the Hagar facility, $0.374 million is directly attributable to vapourization (Table 2, line 1, column (c)).

Remaining Hagar Assets

The remaining assets at the facility of approximately $5.740 million support the overall operations of the facility. Examples of these assets include land, buildings, yard piping, generators and electrical systems and upgrades.

To functionalize the remaining assets at the Hagar facility to the liquefaction, storage and vapourization functions, Union allocated the remaining net plant for these assets in proportion to the functionalization of the directly assigned Hagar net plant described above. Accordingly, of the $5.740 million in remaining net plant, $2.065 million (or 36%) has been allocated to the liquefaction function. $3.305 million (or 58%) has been allocated to the storage function and $0.370 million (or 6%) has been allocated to the vapourization function (Table 2, line 2).

b. Operating and Maintenance Expenses

The second step in the cost allocation review was to determine the function of Hagar operating and maintenance expenses. Examples of operating and maintenance expenses include salary and wages, materials, electricity costs and equipment maintenance.

Of the total 2013 Board-approved Hagar O&M expenses of $1.520 million (Table 1, line 9), Union and KPMG identified $0.057 million in O&M expenses that are directly attributable to the provision of liquefaction. The $0.057 million includes the variable costs associated with liquefying gas to replace the boil off gas that occurs while storing natural gas for system integrity purposes. The variable costs include materials, electricity costs and equipment maintenance.

Notwithstanding the functionalization of the $0.057 million in O&M expenses to the liquefaction function, Union's proposed liquefaction rate is not designed to make a contribution to the recovery of these costs, as these costs are incurred for system integrity purposes only.

The remaining $1.463 million of the 2013 Board-approved O&M expenses at Hagar support the overall operations of the facility. Accordingly, Union is proposing to functionalize the $1.463 million in operating and maintenance expenses in proportion to the functionalization of the Hagar assets.

As described in part a) above, the allocation of the Hagar net plant to the liquefaction function is 36%, 58% to the storage function and 6% to the vapourization function. Accordingly, of the $1.463 million in 2013 Board-approved Hagar O&M expenses, $0.526 million (or 36%) has been functionalized to liquefaction, $0.842 million (or 58%) has been functionalized to storage and $0.094 million (or 6%) has been functionalized to vapourization.

c. <u>Indirect Costs and Taxes</u>

The final step in the cost allocation review was to functionalize indirect costs and taxes. Union is proposing to allocate indirect costs and taxes to the liquefaction, storage and vapourization functions consistent with the 2013 Board-approved cost allocation methodology. The indirect costs and taxes associated with the Hagar facility include general plant, other working capital (excluding gas in storage), property taxes, income taxes and administrative and general expenses.

Consistent with the 2013 Board-approved cost allocation methodology, Union is proposing to functionalize the general plant, other working capital and administrative and general expenses in proportion to O&M and plant. As described in section a) and b) above, Union is proposing to allocate both plant and O&M in proportion to the Hagar net plant. Accordingly, 36% of these indirect costs are allocated to liquefaction, 58% to storage and 6% to vapourization.

The Board-approved cost allocation methodology allocates income taxes in proportion to rate base. The rate base allocated to the liquefaction function is 29%, storage function is 66% and vapourization function is 5%. Accordingly, of the $0.131 million in 2013 Board-approved income taxes, Union is proposing to allocate $0.038 million to liquefaction, $0.087 million to storage and $0.007 million to vapourization.

The Board-approved cost allocation methodology for property taxes allocates the specific property taxes for the assets in proportion to gross plant. Using the Hagar gross plant by function and $0.080 million in 2013 Board-approved Hagar property taxes, Union is proposing to allocate $0.029 million to the liquefaction function, $0.043 million to the storage function and $0.009 million to the vapourization function.

Overall, \$5.098 million of the total \$6.183 million in Hagar revenue requirement was functionalized between the liquefaction, storage and vapourization functions. Based on the proposed cost allocation methodology described above, \$1.804 million of the \$5.098 million in 2013 Board-approved Hagar revenue requirement has been allocated to the liquefaction function, \$2.939 million has been allocated to the storage function and \$0.355 million has been allocated to the vapourization function. Please see Table 3, column (a) below for a summary of the proposed 2013 Board-approved Hagar revenue requirement by function.

Table 3
2013 Board-Approved Hagar LNG Revenue Requirement by Function

Line No.	Particulars	2013 Board-Approved Hagar Costs (\$000's)	System Integrity Only (\$000's)	Total Excluding Direct Assigned System Integrity Costs (\$000's)	Total Excluding Direct Assigned System Integrity Costs (%)
		(a)	(b)	(c) = (a - b)	(d)
	Functionalized Costs:				
1	Liquefaction	1,804	57	1,747	36%
2	Storage	2,939	253	2,687	56%
3	Vapourization	355	-	355	8%
4	Total Functionalized Costs	5,098	310	4,789	100%
5	Compressor Fuel Costs	1,085	1,085	-	-
6	Total Hagar Revenue Requirement (line 4 + line 5)	6,183	1,394	4,789	100%

In addition to the \$0.253 million in costs for gas in storage working capital and \$0.057 million in O&M costs associated with system integrity only (Table 3, lines 1 and 2, column b), the 2013 Board-approved Hagar compressor fuel costs of \$1.085 million are also associated with the provision of system integrity to Union North in-franchise customers. Accordingly, \$1.394

million (Table 3, line 6, column b) of the total $6.183 million in 2013 Board-approved Hagar costs are solely required for system integrity purposes. Union's proposed liquefaction rate is not designed to make a contribution to the recovery of the $1.394 million in costs associated with system integrity only.

With the exclusion of costs directly attributable to system integrity, $1.747 million (or 36%) of $4.789 million has been allocated to the liquefaction function, $2.687 million (or 56%) has been allocated to the storage function and $0.355 million (or 8%) has been allocated to the vapourization function. Please see Table 3, column (c) above for a summary of the proposed 2013 Board-approved Hagar revenue requirement by function.

3. Distribution Cost Allocation Methodology

Prior to its 2013 rates proceeding (EB-2011-0210), Union offered a firm wholesale transportation service in Union North under Rate 77 to provide for the transportation of natural gas to customers outside Union's franchise area. The service allowed for delivery of natural gas owned by the customer through Union's distribution system from the point of receipt on TCPL to the point of consumption at the consumer's distribution system. The rate was designed to provide an appropriate contribution towards the costs of operating the distribution system.

In its 2013 rates proceeding, Union proposed to eliminate the Rate 77 wholesale transportation service rate schedule effective January 1, 2013. The only customer that took service under Rate

77 terminated its contract on October 31, 2008 and no Rate 77 customers were included in the 2013 test year forecast. In its EB-2011-0210 Decision and Rate Order (dated January 17, 2013), the Board approved Union's proposal to eliminate the Rate 77 wholesale transportation service.

For the purposes of determining the contribution that the new Rate L1 service should provide towards the recovery of Union North distribution costs, Union applied the same cost allocation methodology as was previously approved by the Board in EBRO 484 for the Rate 77 wholesale transportation service. This cost allocation methodology is also consistent with Union's 2013 Board-approved allocation of Union North distribution costs.

The primary costs that the new Rate L1 service provides a contribution towards are the capital-related costs and operating expenses associated with the joint-use distribution mains and measurement and regulating equipment utilized in providing the Rate L1 service. Specifically, joint-use distribution mains are used to transport gas from the TCPL interconnect locations to the Hagar LNG facility. The distribution mains are categorized as joint-use because they are used to provide service to the Sudbury-Espanola distribution system and do not exclusively serve an identifiable single customer.

The costs of joint-use distribution mains and joint-use measuring and regulating equipment are allocated to all rate classes based on a "peak and average" demand factor. This allocation factor is determined by taking a 50 percent weighting of a rate class' peak or maximum day demand requirements, and a 50 percent weighting of a rate class' annual volume requirements.

Other distribution costs that the Rate L1 service provides a contribution towards relate to the capital costs associated with regulators. The regulator costs allocated to the new service regulate pressure on the distribution system and are allocated to rate classes based on peak day demands. The other capital-related costs associated with distribution plant (e.g. land, land rights and structures), general plant and intangible plant are allocated in proportion to other distribution plant costs.

Finally, the operating costs that the Rate L1 service provides a contribution towards include an allocation of sales, customer billing and other indirect operating expenses, such as general operating and engineering and administrative expenses. The sales and customer billing operating expenses are allocated based on the average number of customers. The general operating and engineering expenses are allocated in proportion to the allocation of distribution plant costs. Administrative expenses are allocated in proportion to other distribution operating expenses. Based on the 2013 Board-approved cost allocation study and the cost allocation methodology described above, the Rate L1 service will provide a contribution of $0.200 million per year towards the recovery of Union North distribution costs. Please see Schedule 2 for the detailed calculation.

4. Rate Design and Rate Schedule Changes

As indicated above, Union is proposing a new Rate L1 rate schedule and cost-based rate to accommodate an interruptible liquefaction service at the Hagar facility. Union's proposed liquefaction rate design consists of an interruptible rate of $5.096/GJ applied to forecast liquefaction activity. The interruptible rate is intended to make a contribution towards the recovery of existing Hagar liquefaction and storage costs, Union North distribution costs, and to recover the incremental costs associated with the provision of the interruptible liquefaction service.

A description of the proposed rate is provided in more detail below. A copy of the Rate L1 rate schedule with the proposed interruptible rate is provided at Schedule 3.

Union also proposes a maximum interruptible liquefaction rate on short-term (i.e. one year or less) interruptible liquefaction service equal to approximately three times the cost-based interruptible liquefaction rate. The maximum interruptible liquefaction rate will enable Union to respond to the potential market value of its short-term interruptible liquefaction service. Union is proposing to set the maximum interruptible liquefaction rate at $15/GJ.

Union is also proposing to modify the Union North Schedule "A" to accommodate Rate L1 minimum and maximum gas supply charges in $/GJ. The Rate L1 minimum and maximum gas supply charges are based on Board-approved Rate 25 gas supply charges. This modification will enable Union to invoice the Rate L1 gas supply service in energy, consistent with the invoicing of the proposed interruptible liquefaction service.

A black-lined copy of the Union North Schedule “A” is provided at Schedule 4.

Liquefaction Rate Design

Union is forecasting an average of approximately 416,000 GJ per year of interruptible liquefaction activity from September 2015 to December 2018.

To liquefy and store gas, Union will use existing liquefaction and storage facilities at Hagar and incur incremental operating expenses and compressor fuel costs. Union will also require modifications to its existing Hagar facilities and additional facilities which will be recovered through the liquefaction rate. A minimum annual volume requirement will be set to ensure that Union fully recovers the fixed capital-related and operating costs associated with the liquefaction service.

Union proposes an interruptible liquefaction rate of $5.096/GJ, which is comprised of four parts. The first part of the liquefaction rate is calculated using the functionalized liquefaction costs at the Hagar facility, as described in Section 2, adjusted for the estimated number of days Union will provide interruptible liquefaction service.

Union estimates that there will be approximately 167 days on average per year of interruptible liquefaction service. This component of Union's proposed rate design provides for a reasonable contribution to the recovery of fixed costs associated with the assets used to provide the liquefaction service. This rate design is consistent with the rate design of the C1 Dawn to Dawn-TCPL firm transportation rate approved by the Board in EB-2010-0207. Please see Schedule 5, line 10, column (f) for the derivation of the average number of days of liquefaction per year.

The second part of the interruptible liquefaction rate recovers the incremental costs associated with Union's capital investment as well as incremental operating expenses and compressor fuel required to provide the interruptible liquefaction service. The average incremental revenue requirement per year from September 2015 to December 2018 is approximately $1.460 million. Please see Schedule 5, line 8, column (f) for the derivation of the average annual revenue requirement associated with liquefaction costs.

The third part of the liquefaction rate is calculated using the functionalized storage costs at the Hagar facility, as described in Section 2, adjusted for the customers' use of storage capacity. Union forecasts that customers will utilize up to 7,000 GJ per day of storage space, which represents approximately 1.1% of the total Hagar storage capacity of 648,000 GJ. This component of Union's proposed rate design provides for a reasonable contribution to the recovery of fixed costs associated with the assets used to provide storage.

The last part of the interruptible liquefaction rate is calculated using the annual average distribution cost, as described in Section 3, and is intended to make a contribution towards the recovery of existing Union North distribution costs.

The derivation of the interruptible liquefaction rate can be found at Schedule 6. Based on the average forecast level of liquefaction activity of approximately 416,000 GJ per year and Union's proposed interruptible liquefaction rate of $5.096/GJ, Union estimates that the interruptible liquefaction service will generate approximately $2.1 million per year in utility revenue (Schedule 6, line 21).

SCHEDULES

UNION GAS LIMITED
Proposed 2013 Board-Approved Hagar Revenue Requirement by Function

Line No.	Particulars ($000's)	2013 Board-Approved Hagar LNG Costs	Allocation Methodology	Liquefaction	Storage	Vapourization	Total
		(a)	(b)	(c)	(d)	(e)	(f) = (c+d+e)
	Rate Base Calculation						
	Hagar LNG Plant						
1	Gross Plant	22,768	Direct Assignment	8,169	12,529	2,070	22,768
2	Accumulated Depreciation	11,221	Direct Assignment	4,014	5,880	1,327	11,221
3	Hagar LNG Net Plant	11,547		4,155	6,649	743	11,547
4	Hagar LNG Net Plant (%)			36%	58%	6%	100%
	General Plant						
5	Gross Plant	1,095	Hagar LNG Net Plant (line 4)	394	631	71	1,095
6	Accumulated Depreciation	502	Hagar LNG Net Plant (line 4)	181	289	32	502
7	General Net Plant	593		213	342	38	593
8	Total Net Plant	12,140		4,368	6,991	781	12,140
9	Working Capital						
10	Gas In Storage	3,093	Direct Assignment	-	3,093	-	3,093
11	Other	235	Hagar LNG Net Plant (line 4)	85	136	15	235
12	Total Working Capital	3,328		85	3,228	15	3,328
13	Rate Base	15,469		4,453	10,219	797	15,469
14	Rate Base (%)			29%	66%	5%	100%
	Revenue Requirement Calculation						
	Return and Taxes						
15	Return on Rate Base	1,132	Rate Base (line 13)	326	748	58	1,132
16	Income Tax	131	Rate Base (line 13)	38	87	7	131
17	Property Tax	80	Property Tax Allocator (1)	29	43	9	80
18	Total Return and Taxes	1,344		392	878	74	1,344
	Depreciation Expense						
19	Hagar - Local Storage	734	Direct Assignment	289	355	90	734
20	General Plant	148	Hagar LNG Net Plant (line 4)	53	85	10	148
21	Total Depreciation Expense	882		342	440	100	882
	Hagar O&M						
22	Hagar O&M	1,463	Hagar LNG Net Plant (line 4)	526	842	94	1,463
23	Hagar O&M	57	Direct Assignment	57	-	-	57
24	Administrative and General O&M	1,353	Hagar LNG Net Plant (line 4)	487	779	87	1,353
25	Total O&M Expenses	2,872		1,070	1,621	181	2,872
26	Total Revenue Requirement Excluding Compressor Fuel	5,098		1,804	2,939	355	5,098
27	Total Revenue Requirement Excluding Compressor Fuel (%)			35%	58%	7%	100%
	Costs Direct Assigned to System Integrity						
28	Gas in Storage Working Capital (2)	253	Direct Assignment	-	253	-	253
29	Variable O&M Costs	57	Direct Assignment	57	-	-	57
30	Total Costs Direct Assigned to System Integrity	310		57	253	-	310
31	Total Revenue Requirement Excluding Costs Direct Assigned to System Integrity (line 26 - line 30)	4,789		1,747	2,687	355	4,789
32	Total Revenue Requirement Excluding Costs Direct Assigned to System Integrity (%)			36%	56%	7%	100%

Notes:
(1) Functionalized 2013 Board-approved property tax in proportion to gross plant.
(2) $3.093 million in gas in storage working capital represents a revenue requirement of $0.253 (return of $0.226 million and income taxes of $0.026 million).

UNION GAS LIMITED
Derivation of the Average Annual Distribution Revenue Requirement

Line No.	Particulars ($000's)	2016	2017	2018	Total	Annual Average (1)
		(a)	(b)	(c)	(d) = (a+b+c)	(e) = (d / 3)
	Rate Base Calculation					
	Distribution Net Plant					
1	Mains - Joint Use	291	369	402	1,062	354
2	M&R Equipment - Joint Use	201	255	278	734	245
3	Regulators	28	28	28	83	28
4	Other Distribution	79	100	109	287	96
5	Total Distribution Net Plant	598	751	817	2,166	722
	Other Plant					
6	Intangible Net Plant	1	1	1	2	1
7	General Net Plant	27	34	36	97	32
8	Total Other Net Plant	28	34	37	99	33
9	Working Capital	5	6	6	17	6
10	Rate Base (line 5 + line 8 + line 9)	631	791	860	2,282	761
	Revenue Requirement Calculation					
	Return and Taxes					
11	Return on Rate Base (line 10 x 7.32%) (2)	46	58	63	167	56
12	Income Tax	5	7	7	19	6
13	Property Tax	12	15	16	42	14
14	Total Return and Taxes	63	79	86	229	76
15	Depreciation Expense	47	58	63	169	56
	Distribution Operating Expenses					
16	Mains - Joint Use	6	7	5	18	6
17	M&R Equipment - Joint Use	20	25	27	72	24
18	Total Distribution Operating Expenses	26	32	35	93	31
	Other Operating Expenses					
19	General Operating and Engineering	6	8	8	22	7
20	Sales and Promotion	2	2	2	7	2
21	Distribution Customer Accounting	4	4	4	13	4
22	Administrative and General	20	24	25	68	23
23	Total Operating Expenses	32	38	40	110	37
24	Total Revenue Requirement (line 14 + line 15 + line 18 + line 23)	168	208	225	600	200

Notes:
(1) Average revenue requirement is based on the first full 3 years of activity.
(2) 2013 Board-approved rate of return of 7.32% assumes the utility capital structure of debt (61.66% x 6.53%-(0.41)% x 1.31%) and equity (2.75% x 3.05%+36% x 8.93%).

unongas

RATE L1 - NATURAL GAS LIQUEFACTION SERVICE

ELIGIBILITY

For interruptible liquefaction service at the Hagar LNG facility.

SERVICES AVAILABLE

Liquefaction service under this rate schedule will provide for the conversion of gaseous natural gas into liquid natural gas.

MONTHLY RATES AND CHARGES

The following charges will apply per GJ of liquefied natural gas service:

Liquefaction Rate	
Commodity Charge for each unit of gas liquefied ($/GJ)	5.096
Short Term (1 year or less) Liquefaction Rate	
Maximum ($/GJ)	15.000

Minimum Annual Charge

In each contract year, the customer shall take delivery from Union, or in any event pay for, if available and not accepted by the customer, a minimum volume of liquefaction service as specified in the contract. In the event that the customer shall not take such minimum volume, the customer shall pay an amount equal to the deficiency from the minimum volume times a Commodity Charge.

Gas Supply Charge

The gas supply charge, if applicable, is comprised of charges for transportation and for commodity and fuel.
The applicable rates are provided in Schedule "A".

MONTHLY BILL

The monthly bill will equal the rates and charges described above plus all applicable taxes.

DELAYED PAYMENT

The monthly late payment charge equal to 1.5% per month or 18% per annum (for an approximate effective rate of 19.56% per annum) multiplied by the total of all unpaid charges will be added to the bill if full payment is not received by the late payment effective date, which is 20 days after the bill has been issued.

TERMS AND CONDITIONS OF SERVICE

1. Customers must enter into a Liquefaction and Dispensing Agreement with Union prior to the commencement of service.

2. Customers taking service under this rate schedule must be ready to accept interruption at Union's sole discretion.

3. The identified rate represents maximum prices for service. These rates may change periodically. Multi-year prices may also be negotiated, which may be higher than the identified rates.

uniongas

Union Gas Limited
Union North
Gas Supply Charges

(A) Availability

Available to customers in Union's Fort Frances, Western, Northern and Eastern Delivery Zones.

(B) Applicability:

To all sales customers served under Rate 01A, Rate 10, Rate 20, Rate 100, Rate 25 and Rate L1.

(C) Rates

Utility Sales

Rate 01A (cents / m^3)

		Fort Frances	Western	Northern	Eastern
Storage		2.1507	2.3910	3.2252	3.5799
Storage - Price Adjustment		-	-	-	-
Commodity and Fuel	(1)	17.6057	17.6760	17.8171	17.9304
Commodity and Fuel - Price Adjustment		2.0153	2.0153	2.0153	2.0153
Transportation		4.3403	4.2882	5.5650	6.3288
Transportation - Price Adjustment		0.3067	0.3067	0.3067	0.3067
Total Gas Supply Charge		26.4187	26.6771	28.9292	30.1610

Rate 10 (cents / m^3)

		Fort Frances	Western	Northern	Eastern
Storage		1.2015	1.4418	2.2760	2.6307
Storage - Price Adjustment		-	-	-	-
Commodity and Fuel	(1)	17.6057	17.6760	17.8171	17.9304
Commodity and Fuel - Price Adjustment		2.0153	2.0153	2.0153	2.0153
Transportation		3.8695	3.8173	5.0941	5.8579
Transportation - Price Adjustment		0.3067	0.3067	0.3067	0.3067
Total Gas Supply Charge		24.9987	25.2571	27.5092	28.7410

Notes:
(1) The Commodity and Fuel rate includes a gas supply administration charge of 0.1933 cents/m^3.

unionGas

Union Gas Limited
Union North
Gas Supply Charges

Utility Sales

Rate 20 (cents / m³)		Fort Frances	Western	Northern	Eastern
Commodity and Fuel	(1)	17.4239	17.4934	17.6330	17.7451
Commodity and Fuel - Price Adjustment		2.0153	2.0153	2.0153	2.0153
Commodity Transportation - Charge 1		3.0513	3.1266	3.9709	4.4184
Transportation 1 - Price Adjustment		0.3067	0.3067	0.3067	0.3067
Commodity Transportation - Charge 2		-	-	-	-
Monthly Gas Supply Demand		21.9979	24.8397	62.6121	82.3684
Gas Supply Demand - Price Adjustment		-	-	-	-
Commissioning and Decommissioning Rate		4.1328	4.3799	7.5390	9.1960

Rate 100 (cents / m³)		Fort Frances	Western	Northern	Eastern
Commodity and Fuel	(1)	17.4239	17.4934	17.6330	17.7451
Commodity and Fuel - Price Adjustment		2.0153	2.0153	2.0153	2.0153
Commodity Transportation - Charge 1		5.4887	5.5452	6.1784	6.5140
Commodity Transportation - Charge 2		-	-	-	-
Monthly Gas Supply Demand		59.0298	62.3453	106.4130	129.4620
Commissioning and Decommissioning Rate		5.1247	5.3047	7.6458	8.8721

Rate 25 (cents / m³)		Fort Frances	Western	Northern	Eastern
Gas Supply Charge:	Interruptible Service				
	Minimum	14.3135	14.3135	14.3135	14.3135
	Maximum	140.5622	140.5622	140.5622	140.5622

Rate L1 ($ / GJ) (2) (3)		Fort Frances	Western	Northern	Eastern
Gas Supply Charge:	Interruptible Service				
	Minimum			3.7382	
	Maximum			36.7099	

Notes:
(1) The Commodity and Fuel rate includes a gas supply administration charge of 0.1933 cents/m³.
(2) Billing in energy ($/GJ) will only apply to the Rate L1 Natural Gas Liquefaction Service.
(3) Conversion to energy using a heat value of 38.29 GJ/10³m³.

Effective: September 1, 2015
O.E.B. Order # EB-2014-0012

Chatham, Ontario

Supersedes EB-2014-0050 Rate Schedule effective April 1, 2014.

UNION GAS LIMITED
Derivation of the Average Annual Revenue Requirement associated with the
Incremental Hagar Liquefaction Costs from September 2015 - December 2018

Line No.	Particulars ($000's)	2015	2016	2017	2018	Total	Annual Average
		(a)	(b)	(c)	(d)	(e)	(f) = (e / 4)
	Incremental Revenue Requirement Calculation						
	Rate Base Investment						
1	Capital Expeditures	8,685					
2	Average Investment	2,818	8,378	8,071	7,763	27,030	
	Revenue Requirement Calculation						
3	Return on Rate Base (1)	163	483	466	448	1,560	
4	Income Tax (2)	(69)	(30)	(15)	(1)	(115)	
5	Depreciation Expense (3)	154	307	307	307	1,076	
6	Municipal Taxes	14	44	45	45	148	
7	Liquefaction O&M (4)	621	536	942	1,072	3,171	
8	Total Revenue Requirement	883	1,340	1,745	1,872	5,840	1,460
	Forecast Liquefaction Activity						
9	Forecast Liquefaction Sales Activity (GJ)	67,840	339,200	576,640	678,400	1,662,080	415,520
10	Number of Liquefaction Days per Year (5)		106	181	213	500	167

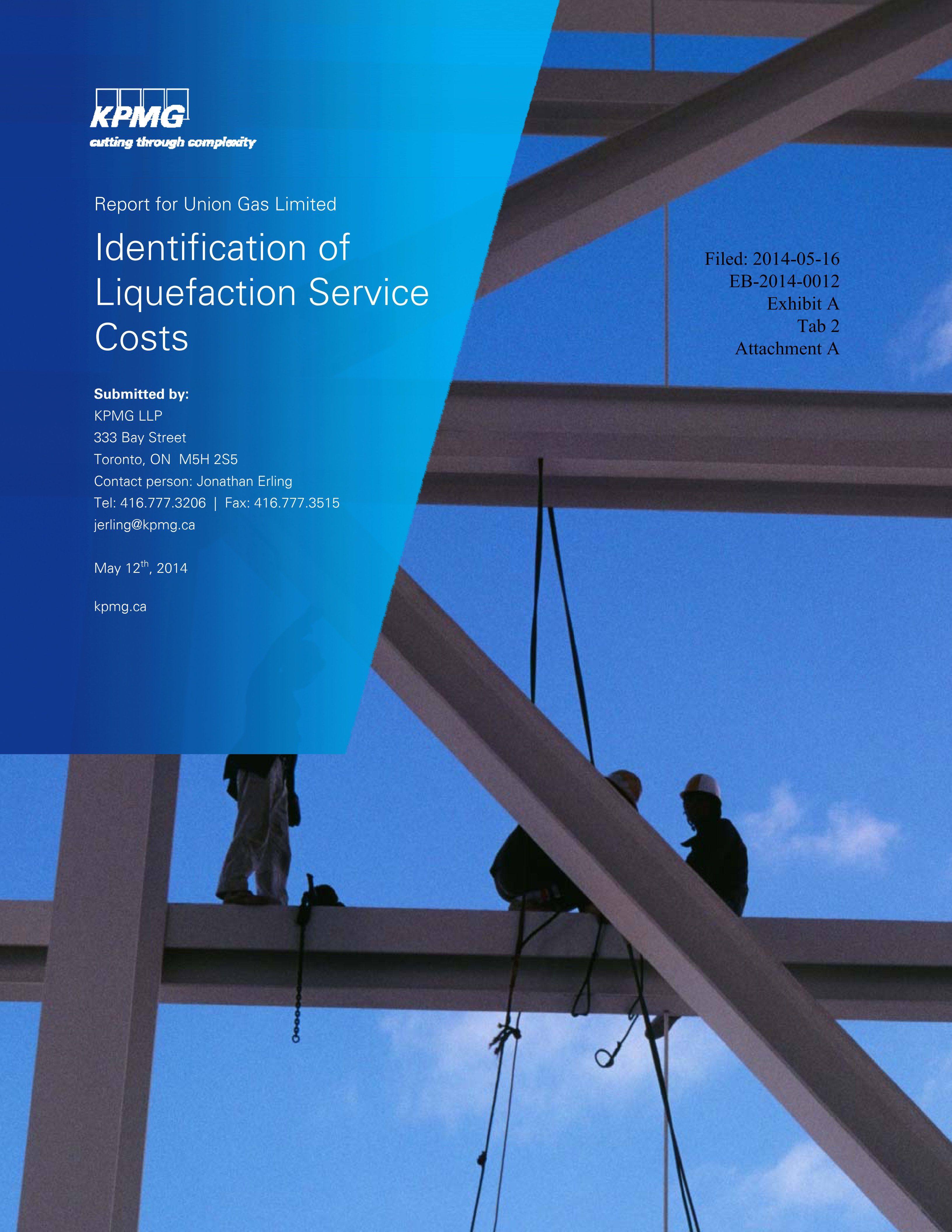
Notes:
(1) The required return assumes a capital structure of 64% long-term debt at 4% and 36% common equity at the 2013 Board-approved return of 8.93%.
(2) Taxes related to the equity component of the return at a tax rate of 26%. Taxes related to utility timing differences are negative as the capital cost allowance deduction in arriving at taxable income exceeds the provision of book depreciation in the year.
(3) Depreciation expense at 2013 Board-approved depreciation rates.
(4) Incremental liquefaction O&M costs as provided in Exhibit A, Tab 1, Table 4.
(5) Days of liquefaction assumes daily liquefaction capacity of 3,186 GJ/day. Average number of days is based on the first full 3 years of activity.

UNION GAS LIMITED
Derivation of Liquefaction Rate
Effective September 1, 2015

Line No.	Particulars		
	Liquefaction Service Commodity Charge:		
	Existing Liquefaction Costs		
1	Hagar Liquefaction Revenue Requirement ($000's)	(1)	1,747
2	Annual Liquefaction Demands for System Integrity (GJs)	(2)	751,950
3	Average Rate per Unit ($/GJ) (line 1 * 1000 / line 2)		2.324
4	Average Number of Liquefaction Days per Year	(3)	167
5	Adjusted Rate per Unit ($/GJ) (line 3 * line 4 / 365)		1.062
	Incremental Liquefaction Costs		
6	Average Annual Revenue Requirement ($000's)	(4)	1,460
7	Average Annual Forecast Liquefaction Sales Activity (GJs)	(5)	415,520
8	Average Rate per Unit ($/GJ) (line 6 * 1000 / line 7)		3.514
9	Liquefaction Commodity Charge ($/GJ) (line 5 + line 8)		4.576
	Storage Space Cost:		
	Existing Storage Service Costs		
10	Hagar Storage Revenue Requirement ($000's)	(6)	2,687
11	Annual Liquefaction Demands for System Integrity (GJs)	(2)	751,950
12	Average Rate per Unit ($/GJ) (line 10 * 1000 / line 11)		3.573
13	Hagar Maximum Storage Space (GJ)	(7)	648,000
14	LNG Storage Space (GJ)		7,000
15	Storage Rate per Unit ($/GJ) (line 14 / line 13 * line 12)		0.0386
	Distribution Service Cost:		
	Existing Distribution Costs		
16	Average Distribution Revenue Requirement ($000's)	(8)	200
17	Average Annual Forecast Liquefaction Sales Activity (GJs)	(5)	415,520
18	Distribution Commodity Rate ($/GJ) (line 16 * 1000 / line 17)		0.4817
19	Total Bundled Liquefaction Commodity Charge ($/GJ) (line 9 + line 15 + line 18)		5.096
	Liquefaction Revenue:		
20	Total Liquefaction Revenue ($000's) (line 17 * line 19 x 4 / 1000)		8,470
21	Average Liquefaction Revenue per Year ($000's) (line 20 / 4)		2,117

Notes:
(1) Schedule 1, line 31, column (c).
(2) Forecast of liquefaction activity reserved for system integrity assumes one storage cycle and approximately 104,000 GJ for boil off gas.
(3) Schedule 5, line 10, column (f).
(4) Schedule 5, line 8, column (f).
(5) Schedule 5, line 9, column (f).
(6) Schedule 1, line 31, column (d).
(7) Storage space calculation assumes maximum storage capacity of 610 mcf and a heat value of 37.51.
(8) Schedule 2, line 24, column (e).

ATTACHMENT A



KPMG
cutting through complexity

Report for Union Gas Limited

Identification of Liquefaction Service Costs

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Exhibit A
Tab 2
Attachment A

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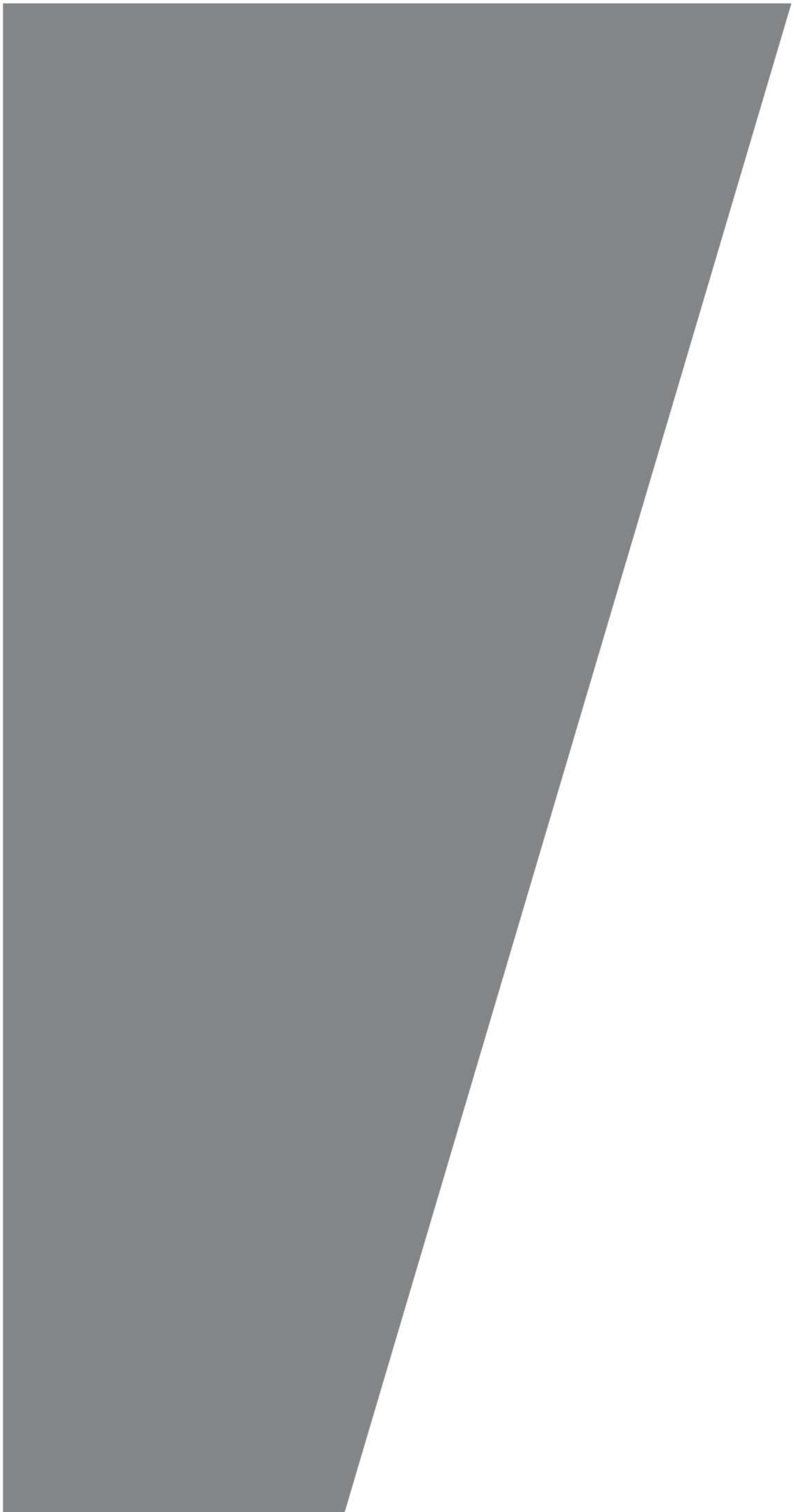

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May 12th 2014

I. Report

A. Background

Union Gas Limited ("Union") has retained KPMG LLP ("KPMG") to develop a cost allocation approach to support the development of an interruptible liquefaction rate. This rate will be used in the supply of Liquefied Natural Gas ("LNG") to wholesale distributors from Union's LNG plant at Hagar. This report summarizes the results of our work.

B. Context

The Hagar LNG plant is currently used for system integrity purposes in Union's northern operating area. From a process perspective, the plant consists of three main elements:

- A liquefaction process, which takes natural gas as an input and converts this gas to liquid form (LNG) by reducing its temperature to the point at which the gas condenses.
- A storage tank, which holds LNG at atmospheric pressure.
- A vaporization process, in which LNG is converted back to a gaseous state through heating and then compressed for injection into Union's natural gas distribution system.

The facility is now dedicated to serving system integrity needs. Thus, LNG from the plant is available to help meet gas supply requirements for Union's Northern system in the event of system contingencies. As an asset dedicated to supporting system integrity, all of the costs of the Hagar plant are currently allocated to utility consumers.

The Hagar plant was designed so that the storage tank can be emptied over a short period of time in order to address unplanned supply outages. Under the current operating regime, the storage tank, once emptied, needs to be refilled only in advance of the following heating season. The result of this operating regime is that the vaporization process is designed to have a much higher capacity than the liquefaction process.

In many years, the storage tank is not emptied (or "cycled") because system contingencies do not arise. When the storage tank is not emptied, use of the liquefaction process is not needed to refill the tank. In any year, however, some minimum amount of liquefaction needs to occur in order to replace LNG that is lost from the tank through "boil-off". (Under the current operating regime, all or most of the LNG that is lost from the tank through boil-off is compressed and then re-injected into Union's distribution system. Gas is therefore not lost from the system.)

One consequence of the operating regime outlined above is that the Hagar facility generally has excess liquefaction capacity that is not required to serve system integrity requirements. This reflects the following:

- Depending on the timing of when the storage tank is emptied, the system generally requires less than the full amount of liquefaction capacity available in order to refill the tank in advance of the next heating season.
- In many years the tank is not emptied, significantly reducing the annual liquefaction requirements at Hagar. (Only limited liquefaction is needed to compensate for boil-off.)
- Once the storage tank has been filled, almost all of the liquefaction capacity will be available for other purposes until the next refill cycle has started. (A small amount of capacity may still be needed to compensate for boil-off during the winter season.)

In light of the availability, from time to time, of excess liquefaction capacity, Union is proposing to make such capacity available on an interruptible basis to wholesale distributors. These distributors are expected to use this capacity to serve the growing demand for LNG by the transportation sector. To support distributors' use of this liquefaction capacity, Union is also proposing to provide them with access to a limited amount of Hagar storage capacity on an interruptible basis.

KPMG has been asked to allocate the costs of the Hagar plant among the various functions undertaken therein as a preliminary step in the development of a rate for the service to be provided to wholesale distributors.

C. General Approach

In designing a cost allocation framework, our general approach is based on the following principles:

- LNG wholesalers should absorb any of the incremental costs associated with providing the new liquefaction service. These include any variable costs associated with additional LNG production.
- LNG wholesalers should assume an appropriate share of the existing costs of the facility. This share should be based on a fully-allocated costing approach, so as to maximize the benefit to the utility of making its infrastructure available for others' use.

These principles will ensure that existing utility customers, at a minimum, do not subsidize the proposed new service and, further, will benefit from the new service by sharing plant fixed costs with LNG wholesalers. The remainder of this report documents the specific elements of our cost allocation proposal.

For the purpose of identifying liquefaction service costs, costs have been analyzed based on the 2013 Board Approved cost allocation study used for Union's 2013 cost of service filing. This will ensure that rates established are consistent with the rates established for other Union services. The resulting rates will be in effect for the current Incentive Regulation period, subject to annual adjustments in the years 2014 through 2018.

D. Issues in the Cost Allocation Process

In this section, we describe some of the key issues in the cost allocation process and our approach to addressing these issues. Key issues are as follows:

- There are many common costs at the Hagar plant.
- Hagar plant costs have not previously been functionalized.
- Actual plant costs are significantly affected by the operating regime in any year.
- Service will be on an interruptible basis.

1. There are many common costs

Many of the operating and maintenance ("O&M") costs associated with the Hagar plant are in the nature of common costs that cannot be directly allocated to an individual function. This reflects the fact that many costs are not linked to individual processes or activities at the plant. These types of common costs include:

- Costs associated with providing a base level of operating staff at the plant on a round-the-clock basis, consistent with legislative requirements and safety / security considerations.
- Costs associated with maintaining general support infrastructure at the plant, including safety and security systems, control systems, and the general building and site envelope.
- Costs for general plant administration, including for a plant manager and an administrative person.
- Operating activities that relate to general plant infrastructure, rather than being tied to a particular process within the plant.

Our proposed approach for dealing with common costs

We propose to allocate the fixed and common portion of existing Board Approved O&M expense based on the functionalization of net plant. In other words, we propose to allocate fixed and common O&M to the three functions (liquefaction, storage and vaporization) based on the allocation of net assets at the plant. The functionalization process (the process used to identify net plant assets by function) is described in more detail in Section G. Results of the plant allocation process are provided below in Table 1; the table shows that 36.0% of net plant assets are allocated to liquefaction.

Table 1
Breakdown of Net Plant by Function

Function	Percent Allocation
Liquefaction	36.0%
Storage	57.6%
Vaporization	6.4%
Total	100.0%

Allocating common costs based on the allocation of net plant by function provides an objective and defensible basis for establishing the costs of each process. Considerations include:

- The cost of net plant and equipment associated with each process is an objective measure of the complexity and effort associated with each process, since equipment requirements and costs are closely linked to relative operational challenges and effort.
- The allocation of net plant assets is stable over time, whereas other measures, such as estimates by personnel of time spent on individual processes, may be highly dependent in any given period on maintenance cycles and/or the operating regime in that particular year. Time allocations are also dependent on subjective recollection and on time keeping accuracy.
- There is limited plant level data on the breakdown of employee time by function.
- Using the same allocator for operating costs as for net plant streamlines and simplifies the cost allocation process.

Potential alternative approaches

Alternatives that we considered but rejected included:

- Allocating costs based on the amount of input fuel needed to run the processes. One problem with this approach is, that with the installation of a new electric compressor to handle boil-off from the storage tank, there is no natural gas fuel associated with the storage function. Also, the amount of fuel required varies with volume throughput and on whether, in any year, the tank is cycled or not. Finally it is not clear that this allocation approach would result in more defensible or appropriate cost allocation than net plant values.
- Collecting information from plant personnel on the time spent on various activities, and then trying to link these activities to particular processes. Disadvantages of this approach were as follows:
  - Given the lack of time-sheet data, it will be dependent on the subjective perceptions of plant personnel with respect to their past activities.

- Time spent in any individual period may be unduly influenced by one-time events, by the operating regime in the period, or by maintenance requirements that may change over time.
- It is relatively more costly to implement and, to the extent it will require the ongoing completion of timesheets by plant personnel, could become administratively burdensome.

- Basing allocations on some measure of throughput volumes. Although appealing at first glance, this approach has a number of significant challenges:
  - Volumes fluctuate widely among years depending on whether the tank is cycled or not.
  - Processes are sequential, so that gas that is vaporized has also been both liquefied and placed in storage. Hence the volumes of various processes are not independent but are strongly related.
  - Costs associated with storage are related to residency time as well as to the volume stored, and this is not reflected in a simple volume measure.
- Basing allocations of measures of the capacity of each process. Problems with this approach include:
  - The vaporization process, by design, has a much higher throughput capacity than the liquefaction process. There is no indication, however, that this higher capacity is reflected in higher operating costs. (In fact, the vaporization process has much lower variable costs per unit than the liquefaction process.)
  - The capacity of storage, which is the amount of gas that can be held in inventory, is conceptually different from the capacity of a process such as liquefaction or vaporization, which is measured in terms of daily throughput.

Precedents elsewhere

In evaluating potential approaches, we also reviewed the approaches used by other utilities when functionalizing the costs of existing LNG facilities. We found the following:

- In a 2012 application to the British Columbia Utilities Commission, FortisBC Energy Inc. ("FEI") allocated costs among liquefaction, storage and vaporization using the percentages 35%, 50%, and 15% respectively. As reported by the utility, these allocation percentages were "established by the LNG Plant Manager based on his experience with the operations".[1] No further elaboration of the rationale for these allocations was provided by FEI. In light of the subjective nature of this approach, we did not consider it further for this study.
- In a 2010 application to La Régie de l'Énergie in Quebec, Gaz Metro allocated the operating costs of its LNG peak shaving facility among liquefaction, storage

[1] *FortisBC Energy Inc., Response to the British Columbia Utilities Commission Information Request No. 1, December 7th, 2012, p. 135.*

and vaporization based on the breakdown obtained for the facility's net plant and equipment. This approach is similar to the one we are proposing to use here.[1]

2. Hagar plant costs have not previously been functionalized

Because the Hagar plant has been treated as an integrated asset dedicated to serving system integrity needs, there has been no prior need to separate its costs among the three main processes (or "functions") provided by the plant, which are liquefaction, storage and vaporization. One of the requirements of this study is therefore to allocate existing costs among these three functions, in order to establish an appropriate basis for the rate to be established for liquefaction service to LNG wholesalers and for their use of storage capacity.

Because costs at the plant have not been allocated among functions before, there has been no need to collect data to support such allocations. This means that limited operational data is available, for example, on the operator time associated with specific activities or on the drivers of maintenance expenditures. The limited availability of operational data influenced our selection of net plant value as the primary cost allocator.

3. Actual plant costs are significantly affected by the operating regime

The 2013 Board Approved costs for the Hagar plant are based on recent operating history. In recent years the plant has not been fully cycled and the LNG storage tank has remained full, or nearly full, throughout the course of the year. Because this operating regime means that the liquefaction process is used to only a limited extent, it must be recognized that future overall facility costs may vary from 2013 Board Approved levels depending on how the facility is operated and on whether the tank is emptied to meet system integrity needs. Some of these cost changes may be unrelated to whether or not the plant sells LNG to a third-party.

It is important to ensure that any cost allocation approach distinguishes between cost changes associated with LNG production for a third party and cost changes associated with whether or not the plant is cycled to meet the system integrity needs of the utility. Costs charged to wholesale distributors should not depend on the use of the facility by the utility, other than to the extent that changes in use by the utility change the incremental costs associated with production of LNG.

4. Service will be on an interruptible basis

Liquefaction service will be provided to LNG wholesalers on an as-available, or interruptible, basis. In other words, wholesalers will not have access to any firm liquefaction capacity on an ongoing basis. Provision of service on an interruptible basis ensures that there is no diminution of Hagar's ability to serve the system

[1] *Société en commandite Gaz Métro*
Demande d'aménagements des modalités à l'égard de l'activité GNL, R-3751-2010, Annex F, p. 65 of 71.

integrity needs of Union's northern system. Similarly, wholesalers' access to storage capacity will be on an interruptible basis.

E. The Process for Cost Allocation

As noted, the objective of this study was to identify the costs that should be allocated by Union to various functions to support the development of an interruptible liquefaction service rate. In this section, we identify the specific steps completed in the allocation process.

The steps completed were as follows:

- We worked with operating staff at Union to identify the fixed and variable elements of each operating cost category. This allowed us to identify those costs that will remain unchanged under different operating regimes and those costs that will vary with the volume of LNG produced. For completeness, we also identified costs that vary with the volume of LNG vaporized, although these costs are not included in the costs allocated to the proposed liquefaction service.
- Working with operating staff, we identified any costs that should be directly attributed to one of the three functions of the Hagar plant, which are liquefaction, storage and vaporization. Any costs directly attributable to a particular function are then directly assigned to that function. These include any variable costs linked to a function, as well as any relevant fixed costs. For example:
  - As identified in the first work step, there are a number of costs that vary with the volume of liquefaction. These include costs for refrigerants, miscellaneous materials, and technician support. We estimated the quantum of such expenses associated with 2013 Board Approved costs and directly assigned these costs to the liquefaction function. These directly attributable expenses amount to only $57,000, out of a total facility revenue requirement of $5.098 million, but should be allocated directly to liquefaction rather than being subject to the allocation process for common and fixed costs. These costs will be greater when more liquefaction occurs. Our estimate of these variable costs forms the basis of Union's projections of the incremental costs associated with LNG production at higher volumes in later years.
  - Going forward, there will be additional costs at the plant for electricity to operate new compressors to be used to re-inject boil-off gas from the storage tank into the distribution system; these costs should be directly assigned to the storage function. These costs, which result from a change in facility configuration, were not included in the 2013 Board Approved costs used as the basis of this study and thus will have to be accounted for separately.
  - Electricity is consumed by the vaporization process to assist in heating LNG up to its vaporization temperature. Since vaporization has not recently occurred, however, these costs are not embedded in 2013 Board Approved costs. These additional costs for vaporization will not influence the liquefaction service rate, since liquefaction service will not call on the vaporization function. Hence, these additional costs have been mentioned here only for completeness.

- We documented operating cost relationships that identify how overall operating costs will change with the volumes of LNG produced. These relationships incorporate our findings on the breakdown of costs into fixed and variable portions, as identified in Step 1. The relationships also identify those costs (both fixed and variable) that should be directly assigned to particular processes, as identified in Step 2. As noted above, any costs that vary directly with LNG production are directly assigned to the liquefaction process. Any remaining common and fixed costs are subject to an allocation process as described in the step below.
- We functionalized common and fixed costs into the activities of liquefaction, storage and vaporization, based on the allocation of net fixed assets among each of the processes. The process for allocating fixed assets is described in Section G.

The overall approach was designed to ensure that the new service will be assigned any incremental costs associated with the preparation of additional volumes of LNG and, in addition, assumes an appropriate share of common and fixed costs associated with general plant operation and the availability of liquefaction capacity.

F. Natural Gas Input Costs

Natural gas is required to run the liquefaction process and to run the vaporization process. Until recently, natural gas was also used to run compressors needed to re-inject boil-off gas into the Union distribution system. Costs for natural gas fuel are recovered in the Compressor Fuel Budget and do not appear in the Plant O&M budget for Hagar.

The fuel required to run the liquefaction process is substantial: for each unit of natural gas converted to LNG, an additional 0.148 units of natural gas are required, on average, to operate the liquefaction process. Much of this fuel is used to operate compressors that drive refrigeration equipment needed to reduce natural gas temperatures. The costs of natural gas needed to run the process have to be included in the costs allocated to the liquefaction process.

G. Review of Facility Net Plant

In this section we summarize our analysis of costs related to plant fixed assets.

Working jointly with operating staff at Union, KPMG reviewed each of the individual asset records for the facility. Based on the description provided for each asset in plant accounting records for Hagar and on staff's knowledge of operations, we allocated each individual record to one of the following asset categories:

- Liquefaction assets.
- Storage assets.

- Vaporization assets.[1]
- Common assets (i.e. assets that cannot be linked to a specific process).

Of the total net book value of assets, 50.3% of assets can be directly linked to one of the processes of liquefaction, storage or vaporization. This left 49.7% of assets that were categorized as common assets or that could not be linked to a specific process. Of the assets that can be linked to specific processes, 36.0% are associated with liquefaction.

We allocated common assets to processes based on the shares of assets that could be linked directly. This meant that 36.0% of all assets were allocated to liquefaction. Allocation percentages determine the fixed plant (and the Rate Base) associated with each process and, as discussed above, are also used to allocate common operating costs.

Depreciation expense was calculated by Union's plant accounting department for those assets directly allocated to one of the three processes. This accounted for 54.7% of total depreciation expense for Hagar local assets. The remaining depreciation expense for assets at Hagar was then allocated among processes in the same proportion. Depreciation for general plant was allocated to processes based on the proportion of net plant allocated to each process, which is consistent with how Union has allocated general plant depreciation in other circumstances.

H. Summary of Costs Allocated to Functions

In this section, we summarize the various cost elements that have been allocated to various functions based on Board Approved costs for the 2013 period.

Table 2 shows the allocation of fixed and common costs at Hagar among the functions of liquefaction, storage and vaporization. Costs for storage have been further divided between costs associated with storage service and costs associated with existing storage inventory. Storage costs have been divided because LNG distributors using the new service will be funding the costs of any of their own inventory that will be placed into storage. As a result, these distributors should not be expected to assume any of the costs associated with existing storage inventory in the development of rates charged for its use of Hagar facilities.

Additional observations with respect to Table 2 are as follows:

- The value of gas in storage at Hagar is allocated entirely to storage inventory for the purpose of calculating the Rate Base of each plant process.
- "Other" working capital is allocated is the same proportions as Net Plant.
- Fixed operating costs at Hagar are allocated in proportion to the Net Plant associated with each process, rather than in proportion to each process's share of

[1] *Assets allocated to the vaporization category included some compressors that are used to provide pressure support to the distribution lines adjacent to Hagar. The compressors could be considered part of a fourth process but were aggregated with vaporization for the purpose of our analysis and discussion. This has no effect on the costs allocated to the liquefaction process and helps to simplify the presentation of our results.*

overall Rate Base. (The allocation of Rate Base differs from Net Plant because the value of LNG in storage is allocated entirely to the Storage Function.)

As shown in Table 2, a total of $1.747 million in fixed costs at Hagar are allocated to the liquefaction process. These relate to all liquefaction volumes, including those on behalf of the utility, and thus going forward these costs will need to be allocated between the utility and LNG distributors on an appropriate basis. For the period covered by the 2013 cost allocation study, there are also $57,000 in costs that are directly related to the volume of LNG production. For 2013, all of these costs are related to liquefaction needed to address boil-off from the storage facility. These costs are thus attributable to the utility.

Table 2
Allocation of 2013 Board Approved Costs

Functionalization of Haggar Costs Based Upon
Board Approved 2013 Cost Allocation Study

Line No.	Particulars ($000's)	Hagar LNG Costs [1]	LNG	Storage Services	Storage Inventory	Vapourization
	Rate Base Calculation					
1	Net Plant [2]	12,140	4,368	6,991	-	781
			36.0%	*57.6%*	*0.0%*	*6.4%*
	Working Capital					
2	Gas In Storage [3]	3,093	-	-	3,093	-
3	Other	235	85	136	-	15
4	Total Working Capital	3,328	85	136	3,093	15
5	Rate Base	15,469	4,453	7,126	3,093	797
			28.8%	*46.1%*	*20.0%*	*5.1%*
	Fixed Cost Recovery					
6	Return on Rate Base [4]	1,132	326	522	226	58
7	Income Taxes	131	38	61	26	7
8	Property Taxes	80	29	43	-	9
9	Depreciation Expense	882	342	440	-	100
	Subtotal - Capital Charges	2,226	734	1,065	253	174
10	Hagar LNG [5] - Common Fixed Costs	1,463	526	842	-	94
11	Administrative and General - Fixed	1,353	487	779	-	87
12	Subotal - Common Operating Costs	2,816	1,013	1,621	-	181
13	Fixed Costs for Recovery	5,041	1,747	2,687	253	355
14	Variable Costs	57	57	-	-	-
15	Total Costs for Recovery	5,098	1,804	2,687	253	355

Notes
(1) The Hagar LNG costs include the Iroquois Falls compressor station.
(2) Includes $0.593 million general plant costs.
(3) Gas in storage calculation assumes 642 PJ x 4.823 $/GJ.
(4) The rate of return of 7.32% assumes the utility capital structure of debt (61.66%*6.53%-(0.41)%*1.31%) and equity (2.75%*3.05%+36%*8.93%).
(5) The Hagar LNG common fixed costs include $1.155 million associated with the plant operations, including salary and wages, materials and other operating expenses. The costs also include $0.308 allocation of STO related fixed expenses.

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As a firm with locations in more than 30 cities across Canada, we are actively connected to the communities where we operate – as a business, as an employer – in every sense. The issues that impact our communities are the same issues that impact our people and their families, our clients and our operations. So making a commitment to having a positive impact is how we recognize the significance of our relationship with the communities where we operate and live.

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