ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
BOARD STAFF INTERROGATORY #1

INTERROGATORY

Issue: A-3
Are the costs of the facilities and the rate impacts to customers appropriate?

REF: Exhibit A, Tab 2, Schedule 4, pages 5-6

Preamble
Enbridge states that the originally proposed Segment A initiation point was reinstated to Parkway West to interconnect with Union Gas as opposed to the previously proposed initiation point at Bram West with TransCanada.

Questions
a) Please provide the rationale, from an operational and economics standpoint, for the change in the initiation point from Bram West to Parkway West.

b) Please provide a comparison of the annual costs that Enbridge would otherwise pay to TransCanada for the use of TransCanada's Mainline from Parkway to the Bram West interconnect and Enbridge's revenue requirement for the segment proposed to be built from Parkway to Bram West.

c) Would the proposal for an initiation point at Parkway result in duplication of existing facilities and lead to the underutilization of existing natural gas infrastructure?

RESPONSE

a) Please refer to Exhibit A, Tab 3, Schedule 9, paragraph 2. The rationale for changing the initiation point was due to the termination of the MOU with TransCanada. Although Enbridge continues to agree with the principles embodied within the MOU, specifically open market access to capacity on Segment A, and the coordinated regional development of infrastructure in the GTA region, the MOU is no longer in effect. Enbridge is continuing discussions with other market participants, including TransCanada, but at this point in time has no assurances that a Bram West interconnection to the mainline could be pursued and meet the required in service timeline, nor that TransCanada will provide the open market access at reasonable transportation rates for either Enbridge, or other shippers.

Witnesses: J. Denomy
C. Fernandes

Changing the initiation point resolves some of these issues and is directly within Enbridge's control, so it is prudent to make this change at this point in time. Operationally, the differences in gas flows will be minor, as with the previous Bram West interconnection, gas flows upstream were all through Parkway West. Therefore the only difference in the gas flows are the additional approximately 6.5 km of new pipeline from Parkway West to Bram West, which would occur in the same utility corridor, along the same path, but on newly constructed Enbridge pipeline currently, as opposed to existing TransCanada pipeline in the previous case.

From an economics standpoint, as outlined in Exhibit A, Tab 3, Schedule 9, paragraph 11 and Economic Sensitivity Results Attachment 3, there is a tradeoff of the capital cost of building the approximately 6.5 km of net new pipeline from Parkway West to Bram West, with the toll savings from TransCanada Parkway to Bram West transport service in the previous case.

b) The estimated annual costs for Enbridge for its customers in the GTA of the Parkway to Bram West toll is shown at Exhibit A, Tab 3, Schedule 9, Table A4. The 'Total Cost' row under 'Expected Contracting With GTA Project Facilities Approved', Service Path = 'TCPL FT – EGD & Direct Purchase Parkway to Bram West CDA' shows the estimated toll cost by year for this approximately 6.5 km segment of the path for the 800 TJ/d of capacity as per the previous submission. Forecast is $4.4 million for the 2015 calendar year, which is a partial gas year, and $26.3 million in the 2016 year, 1^{st} full year of forecast toll. The table shows a forecast for all years from 2015 to 2025.

As a comparison, the Revenue Requirement for the entire 27.4 km Segment A is shown in Exhibit E, Tab 1, Schedule 2, Attachment 1. The revenue requirement is $4.2 million for the 2015 (partial gas year) and $33.7 million for 2016 ($1^{st}$ full gas year). As per Enbridge's proposed approach, for the 800 TJ/d of capacity for distribution rate payers, 40% of this revenue requirement (or approximately $13.5 million) would be allocated as described in Exhibit E, Tab 1, Schedule 2, paragraph 8.

The annualized operational costs in the current base case are lower than the annual costs of the expected Tolls for the Parkway to Bram West segment of the path.

c) The path from Parkway (West) to Bram West already has multiple lines, some as part of the Transmission system and others as part of the Distribution system, all in the same designated utility corridor. Parkway to Bram West is a portion of the Parkway to Maple path that is currently constrained on the Transmission system.

Witnesses: J. Denomy
C. Fernandes

Utilization of the existing facilities from Parkway to reach Bram West is a technically viable solution as previously proposed. However, twinning of this portion of the path will not result in underutilization of the existing infrastructure because the existing facilities along the entire path from Parkway to Maple are fully utilized. The coordinated build out of regional infrastructure to meet incremental demand for transport can be staged in a manner to ensure a high degree of correlation between incremental demand and capacity additions.

Witnesses: J. Denomy
C. Fernandes

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
BOARD STAFF INTERROGATORY #2

INTERROGATORY

Issue: A-3
Are the costs of the facilities and the rate impacts to customers appropriate?

REF: Exhibit A, Tab 3, Schedule 9, page 3, paragraph 5

Preamble
Enbridge states that: "With respect to the dependency on Segment A for transportation benefits along the Parkway to Maple path, it is recognized that there has not been an application for the required facilities for the Albion to Maple build, and the timing of the build out is currently uncertain….However, the distribution benefits that accrue to Enbridge's customers are not dependent on the build out from Albion to Maple."

Questions
a) In the event that the in-service date for the Albion to Maple segment is delayed beyond the forecast in service date for Segment A, would this result in a greater proportional allocation of costs to Enbridge's ratepayers for Union's Brantford-Kirkwall Parkway D and Parkway West facilities costs? If so, please quantify the annual costs that Enbridge ratepayers would have to bear if the incremental volumes of Gaz Métro and other potential shippers would be deferred by a year. Please include all underlying assumptions.

RESPONSE

a) Enbridge is unable to provide a response. This question is more appropriately directed to Union Gas.

Witness: J. Denomy

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
BOARD STAFF INTERROGATORY #3

INTERROGATORY

Issue: A-3
Are the costs of the facilities and the rate impacts to customers appropriate?

REF: Exhibit A, Tab 3, Schedule 9, page 4, paragraph 7

Preamble
Enbridge states that the open season will close no later than September 6, 2013 and will be used to allocate the available transportation capacity on Segment A.

Questions
a) Please provide the rationale for setting the open season closing date to September 6, 2013.

b) Please provide a link to Enbridge's Open Season web page for Segment A.

RESPONSE

a) Per the OEB's Storage and Transportation Access Rule (Section 2.2.1(i)(d)), a transmitter is required to allow a minimum of 30 business days between the time an Open Season notice for new capacity is issued and the close of the Open Season period. Enbridge issued the Albion Pipeline Open Season at the end of day on July 24. Therefore, September 6 was chosen to provide for the required 30 business day Open Season period.

b) Enbridge's Open Season documents for Segment A can be found at www.enbridgegas.com/openseason.

Witness: M. Giridhar

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
BOARD STAFF INTERROGATORY #4

INTERROGATORY

Issue: A-3
Are the costs of the facilities and the rate impacts to customers appropriate?

REF: Exhibit E, Tab 1, Schedule 2, page 2, paragraph 7

Preamble
Enbridge states that: “In the event there are no shippers for the transport service, distribution ratepayers will be allocated the entire revenue requirement. The Company will be working with shippers on the Segment A pipeline to include the placement of Financial Backstopping Agreements (“FBAs”). The shippers are expected to bear some of the risk on upfront costs associated with the Segment A pipeline, in particular the approximately $55 million in costs associated with NPS 42 as compared to NPS 36, and any consequences of a delay in the Albion to Maple path.”

Questions
a) Please explain the purpose and content of a FBA.

b) Please file a copy of a model or a form of the FBA.

c) Please clarify if this means that shippers would be expected to pay the Parkway to Albion Transportation Service rate to Enbridge starting from the in-service date of Segment A regardless of when the Albion to Maple path is completed. If not, please indicate if Enbridge expects that distribution customers would be at risk for any delays.

d) Please clarify how shippers would be expected to bear some of the upfront costs associated with Segment A. Would this be done by means of reduced financial securities? Please explain.

e) Please provide the incremental benefits to distribution ratepayers for building capacity on the Segment A pipeline that is incremental to their needs.

Witness: C Fernandes
M. Giridhar

RESPONSE

a) Please see response to CCC Interrogatory #31 at Exhibit I.A3.EGD (Update).CCC.31 (a).

b) Please see response to BOMA Interrogatory #2 at Exhibit I.A1.EGD (Update).BOMA.2.

c) In the event that Enbridge enters into definitive agreements with shippers with an in-service date of November 1, 2015, and if Enbridge's facilities are in service by this date, shippers will be obliged to take service as of this date or a later date as defined in the agreement. This is standard practice for transmission service in Ontario.

d) Under the terms and conditions of the Precedent Agreement and FBA, shippers on the Albion Pipeline will agree to be liable and indemnify Enbridge for certain costs to develop and construct the facilities, the Pre-Service Costs. Per the FBA, based on shippers' failure to satisfy or if shippers have waived certain conditions precedent by the required date or other shipper breach of the Precedent Agreement, shippers will be required to reimburse Enbridge their proportionate share of the Pre-Service Costs. Enbridge may require the shipper to provide financial assurances in the form and amount reasonably required per the FBA.

e) The NPS 42 Segment A pipeline is designed to meet the prevailing transmission pressure at Parkway/Parkway West, and thus account for the eventual coordinated build out of the Parkway to Maple path, utilizing the current discharge pressure from Parkway/Parkway West. With this arrangement, 60% of the revenue requirement of this pipe will be borne by ex-franchise shippers.

   In the event that no shippers take transmission service, Enbridge has determined that the NPS 42 size for the Albion pipeline is required to meet its distribution needs of 800 TJ/d in the GTA, in conjunction with an inlet pressure of 530 psi which is in line with operating pressures of other distribution pipelines.

   Thus, the NPS 42 for Segment A provides the flexibility of Segment A functioning as a transmission line at prevailing transmission pressure with accompanying revenue, or a distribution line at distribution pressures.

Witness: C Fernandes
M. Giridhar

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO APPrO INTERROGATORY #14

INTERROGATORY

A.3 Are the costs of the facilities and the rate impacts to customers appropriate?

Reference: EB-2012-0451 Exhibit A Tab 3 Schedule 9 Paragraph 33 & 34 Updated 2013-07-22

Preamble: Enbridge calculates the impact to all rate classes on a stand-alone basis and also net of gas cost savings.

a) Using the assumption that the Board were to find that no GTA project costs were to be allocated to unbundled customers, please recalculate the rate impact to all rate classes:
   i. On a stand-alone basis, and
   ii. Net of gas cost savings.

RESPONSE

a) i) The table below depicts the rate impacts assuming that none of the GTA project costs are allocated or recovered from EGD's unbundled customers. The estimated rate impacts (relative to April 1, 2013 QRAM rates) are based on the 2016 revenue requirement with no gas cost savings.

		BUNDLED RATES	
Rate Class		**Sales Service**	
1		1.7%	
6		1.7%	
9		0.6%	
100		1.2%	
110		1.2%	
115		1.1%	
135		0.6%	
145		1.1%	
170		0.8%	
200		1.9%	
		UNBUNDLED RATES	
125		0.0%	
300		0.0%	

b) ii) The table below depicts the rate impacts assuming that none of the GTA project costs are allocated or recovered from EGD's unbundled customers. The estimated rate impacts (relative to April 1, 2013 QRAM rates) are based on the 2016 revenue requirement inclusive of gas cost savings.

		BUNDLED RATES
Rate Class		**Sales Service**
1		-2.1%
6		-3.2%
9		-4.2%
100		-5.7%
110		-5.7%
115		-6.3%
135		-6.9%
145		-6.1%
170		-7.2%
200		-4.5%
		UNBUNDLED RATES
125		0.0%
300		0.0%

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
APPrO INTERROGATORY #15

INTERROGATORY

A.3 Are the costs of the facilities and the rate impacts to customers appropriate?

Reference: EB-2012-0451 Exhibit E Tab 1 Schedule 2 Paragraph 7 Updated 2013-07-22
EB-2012-0451Exhibit E Tab 1 Schedule 1 Paragraph 12 Updated 2013-07-22
EB-2012-0451 Exhibit A Tab 3 Schedule 9 Paragraph 33 & 34 Updated 2013-07-22

Preamble: In the first reference, Enbridge indicates that if there are no shippers for the transportation service; that distribution ratepayers will be allocated the entire revenue requirement for Segment A.

a) In the event that Enbridge is successful in its open season and obtains some transportation customers but significantly less than the 1200 TJ/d of capacity that is being allocated to transportation customers, how will Enbridge allocate the costs of Segment A? Discuss all scenarios ranging from a very small volume of transportation customers to the full 1200 TJ/d of new transportation capacity.
b) Enbridge is using part of the 800 TJ/d of capacity of segment A for infranchise 10 year growth, which may result in a portion of Enbridge's distribution capacity not being fully utilized in the initial period:
   i. Given that this corridor has been constrained in the past, will Enbridge sell discretionary services?
   ii. If yes, how will the rate for these services be determined?
   iii. If incremental revenue is generated, what is Enbridge's forecast for the period from in-service to 2018 and how will this revenue be allocated?
c) In the event that no transportation shippers sign up for any capacity, please:
   i. Update the PI and NPV illustrated in the second reference.
   ii. Update the PI and NPV under the assumption that the Board does not agree that unbundled customers should be allocated any of the costs of the GTA project.
   iii. Update the rate impact in the third reference illustrating the rate impacts to all rate categories on a stand-alone basis and net of gas cost savings.
   iv. Please update the rate impact to all rate classes both on a stand-alone basis and net of gas costs using the assumption that the Board does not agree that unbundled customers should be allocated any of the costs of the GTA project.
   v. Please provide Enbridge's intentions with respect to the Segment A design and sizing.
   vi. Explain how costs would be allocated in the future if some transportation contracts were subsequently acquired after Segment A goes into service.

Witnesses: C. Fernandes
M. Giridhar
A. Kacicnik
S. Murray

RESPONSE

a) As part of its Binding Transportation Open Season offering for the Albion Pipeline project, the Company developed range rates for Rate 332 Contract Demand Charge which will be used to recover 60% of the revenue requirement allocated to transportation shippers from Segment A.

   The bottom of the range rate was developed based on the assumption that the entire 1,200 TJ/d would be utilized by transportation shippers. The top of the range was developed based on the assumption that 538 TJ/day would be utilized by Gaz Metro, Union Gas and Enbridge for its Eastern region. The makeup of the 538 TJ/day can be found at Exhibit A, Tab 3, Schedule 9, page 2, paragraph 4.

   The range rates allow the Company to accept bids within the Binding Transportation Open Season offering and then set them depending on the amount of contracted capacity. This will ensure that the cost of the allocated portion of Segment A is recovered from transportation shippers.

b) The 800 TJ/d of capacity for Distribution is expected to be fully utilized at peak system conditions starting in the first year. Growth in GTA area demand will be met through other paths. Enbridge is not forecasting discretionary service revenue along this path, as it does not foresee the opportunities to do so at this point in time. If there are opportunities in the future, the additional revenues can be dealt with under any prevailing arrangement.

c)
   i. Please see Exhibit A, Tab 3, Schedule 9, Attachment 3, Column 5.

   ii. Please see response to APPrO Interrogatory #13 found at Exhibit I.A2.EGD (Update).APPrO.13 a).

   iii. The tables below depict the rate impacts assuming the entire cost of the Segment A pipeline is recovered from EGD distribution customers. Table 1 depicts the estimated rate impacts (relative to April 1, 2013 QRAM rates) based on the 2016 revenue requirement with no gas cost savings. Table 2 depicts the estimated rate impacts (relative to April 1, 2013 QRAM rates) based on the 2016 revenue requirement inclusive of gas cost savings.

Witnesses: C. Fernandes
M. Giridhar
A. Kacicnik
S. Murray

Table 1

		BUNDLED RATES	
Rate Class		**Sales Service**	
1		2.3%	
6		2.3%	
9		1.0%	
100		1.9%	
110		1.9%	
115		1.8%	
135		1.3%	
145		1.8%	
170		1.6%	
200		2.7%	
		UNBUNDLED RATES	
125		23.5%	
300		8.6%	

Table 2

		BUNDLED RATES	
Rate Class		**Sales Service**	
1		-1.5%	
6		-2.5%	
9		-3.8%	
100		-5.0%	
110		-5.0%	
115		-5.6%	
135		-6.3%	
145		-5.4%	
170		-6.5%	
200		-3.7%	
		UNBUNDLED RATES	
125		23.5%	
300		8.6%	

Witnesses: C. Fernandes
M. Giridhar
A. Kacicnik
S. Murray

iv. The tables below depicts the rate impacts assuming the entire cost of the GTA project is recovered from EGD distribution customers excluding unbundled customers. Table 1 depicts the estimated rate impacts (relative to April 1, 2013 QRAM rates) based on the 2016 revenue requirement with no gas cost savings. Table 2 depicts the estimated rate impacts (relative to April 1, 2013 QRAM rates) based on the 2016 revenue requirement inclusive of gas cost savings.

Table 1

		BUNDLED RATES	
Rate Class		**Sales Service**	
1		2.4%	
6		2.4%	
9		1.0%	
100		1.9%	
110		1.9%	
115		1.8%	
135		1.3%	
145		1.8%	
170		1.6%	
200		2.8%	
		UNBUNDLED RATES	
125		0.0%	
300		0.0%	

Witnesses: C. Fernandes
M. Giridhar
A. Kacicnik
S. Murray

Table 2

		BUNDLED RATES	
Rate Class		Sales Service	
1		-1.4%	
6		-2.4%	
9		-3.8%	
100		-4.9%	
110		-4.9%	
115		-5.6%	
135		-6.3%	
145		-5.3%	
170		-6.5%	
200		-3.7%	
		UNBUNDLED RATES	
125		0.0%	
300		0.0%	

v. Enbridge is designing the pipeline for current Parkway Transmission pressure in a Class 4 location with a NPS 42 size pipeline. This allows for maximum flexibility, as the pipeline can be used for distribution only purposes, and also for the eventual transmission build out of the Parkway to Maple path.

vi. In the event that no shippers sign up for any capacity for the 2015 in service date of Segment A, and at a future date, shippers were subsequently acquired, Enbridge would expect to allocate costs using the same principles as currently proposed in the Rate 332 methodology.

Witnesses: C. Fernandes
M. Giridhar
A. Kacicnik
S. Murray

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
APPrO INTERROGATORY #16

INTERROGATORY

A.3 Are the costs of the facilities and the rate impacts to customers appropriate?

Reference: EB-2012-0451 Exhibit A Tab 3 Schedule 9 Paragraph 4 Updated 2013-07-22

Preamble: Enbridge indicates that 170 TJ/d of capacity in Segment A will be used to serve Enbridge's Eastern Region

a) This new capacity of 170 TJ/d does not appear to be in Enbridge's initial filing for the GTA Reinforcement Project. Please discuss the rationale for this capacity to be added at this time.
b) Please explain if this will be used to serve Enbridge's system supply and the balancing requirements of Enbridge's bundled customers or if Enbridge is using this for some other reason.
c) If this capacity is to be utilized by Enbridge, is it Enbridge's intention to enter into a transportation contract for this capacity, or allocate capacity and its related costs to the customers in Enbridge's Eastern Region without a contract? Explain.
d) In the event that Enbridge enters into a transmission contract and allocates capacity to the Eastern Region, discuss how the cost of this capacity will be allocated to the various rate classes and please show the rate impact to all rate classes.
e) Please discuss Enbridge's plan to access downstream capacity from Albion to Maple and on the TransCanada system.
f) Please discuss how the costs of this 170 TJ/d of capacity downstream of Albion will be allocated to the various rate classes.

RESPONSE

Please note there are two Interrogatories from APPrO that are number 16, I.A3.EGD (Update).APPrO.16 and I.D5.EGD (Update).APPrO.16.

a) Enbridge recently contracted for non-renewable long haul firm transportation from Empress to the Enbridge EDA. This non-renewable capacity expires in 2015. The 170 TJ/d of new short haul capacity will be used to displace the incremental non-renewable long haul firm transportation recently contracted for on the TransCanada system and peaking supplies. When contracting for this non-renewable firm transportation capacity, Enbridge was concerned about the availability of

Witnesses: J. Denomy
A. Kacicnik

discretionary transportation to the Enbridge EDA over the next two years and the pricing of discretionary service given the pricing discretion granted to TransCanada by the NEB in the RH-003-2011 Decision. TransCanada has priced monthly blocks of STFT, which would have been utilized to supply the Enbridge EDA, at 1200% of the corresponding FT toll from Empress to the Enbridge EDA in addition to deeming a portion of existing firm capacity currently serving markets in eastern Ontario and Quebec as required for the Energy East Pipeline Project.

b) Enbridge will use this capacity to provide transportation and seasonal balancing services to its bundled customers.

c) Enbridge intends to enter into a contract for this capacity. Costs related to this capacity will be allocated to Enbridge's bundled customers according to the Board-approved cost allocation and rate design methodology for transportation and seasonal balancing service costs. Note that Board-approved cost allocation and rate design methodology are based on postage stamp principles. Postage stamp rates result in the same gas supply or transportation or load balancing or delivery rates for all customers within the same customer rate class regardless of the customer's location within the Enbridge's franchise area.

d) N/A. This question is not applicable. Please see the response to c) above for allocation and recovery of this capacity costs from Enbridge's bundled customers.

e) Please see the response to a) above.

f) Costs related to 170 TJ/d of capacity downstream of Albion will be allocated to Enbridge's bundled customers according to the Board-approved cost allocation and rate design methodology for transportation and seasonal balancing service costs. Note that Board-approved cost allocation and rate design methodology are based on postage stamp principles. Postage stamp rates result in the same gas supply or transportation or load balancing or delivery rates for all customers within the same customer rate class regardless of the customer's location within the Enbridge's franchise area.

Witnesses: J. Denomy
A. Kacicnik

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
CONSUMERS COUNCIL OF CANADA INTERROGATORY #30

INTERROGATORY

A3. Are the costs of the facilities and rate impacts to customers appropriate?

Reference: Ex. A/T2/S1/p. 8

a) The evidence indicates that the updated estimated cost of the GTA project is $686.5 million. How does this compare to the costs set out in the original Application of December 21, 2012 and the updated application of 2013-04-15? Please describe how the new proposals compare to the proposals set out in the original Application. Please explain the reason for the differences in cost between the three different proposals.

b) Specifically please show how the current updated proposal differs from that originally filed on December 21, 2012 (Parkway to Albion). Please compare and contrast the DCF analysis of that filing with the current update.

c) Please specifically address the following changes from the 2013-04-15 filing (BramWest to Albion 42 inch pipeline) to the current proposal:
   i) The average O&M costs have been reduced from $14.0 million (May 15 filing) to $13.3 million (July 22 filing) and notwithstanding the longer and larger pipeline. Please explain the reasons for this.
   ii) The total transportation savings have increased from $392,136,859 to $1,732,650,739. Please specify the basis for these savings including the assumptions in respect to Direct Purchase change in current contracting practice once the project is completed.
   iii) Transportation service charges have increased from $382,373,164 to $471,256,624.
   iv) Annual Volumes have changed from 751,758,344 to 706,621,245

Witnesses: J. Denomy
C. Fernandes
T. Horton
B. Madrid
S. Murray

RESPONSE

For all responses, please also review Exhibit A, Tab 2, Schedule 4 that summarizes the changes for each update.

a) Please see attachment for a comparison and variance analysis of each of the four cost scenarios filed as part of this Application.

b) The Table below shows the major catgeories contained within the economic feasibility DCF from the original filing to the Current Base Case. The description of difference field describes the major reasons for change in each category. In addition to the changes below, the filing from 12/21/2012 used 2012 feasibility parameters while 2013 parameters were used in the current base case.

Column #	1	2	
Document Type:	**Evidence**	**Evidence**	
Scenario Description:	Originally filed **36''**	Current Base Case **42''**	
Filed Date:	12/21/2012	7/22/2013	
Reference:	Exh E/T1/S1, pg 6 & Attachment	Ex. E, Tab 1, Sch. 1	
Capital Investment			
			Description of difference
Total Proposed Capital	$575,309,331	$652,144,124	Segment A is ~1.5 km longer and NPS 42 in current base case, versus NPS 36 original. Different construction schedules and in service dates between the two submissions drive differences in construction labour and project execution costs as well as IDC.
Total Transportation Savings	$511,151,468	$1,732,650,739	Savings baseline has changed from discretionary services previously in use, to a future base case of long haul FT at new mainline tolls
Total Transportation Services Charge	$0	$471,256,624	Shared usage of Segment A pipeline adds revenue for the transportation services from Parkway West to Albion
Total Distribution Revenues	$4,843,361,699	$4,546,724,222	As per Update #4 customer original customer additions were in error and included additions from Markham gate influence area
Total Customer Additions (2015 - 2024)	156,181	146,337	As per Update #4 customer original customer additions were in error and included additions from Markham gate influence area
SUMMARY OF RESULTS			
Net Present Value (40 years)	$20,290,078	$667,432,377	
Profitability Index (40 years)	1.02	1.73	

c)

i) The reduction in average O&M costs between the requested periods is the result of the reduction in forecasted customer additions, as updated on June 3, 2013 (Update #4). In total, customer additions were adjusted down from 156,181 to 146,337.

Witnesses: J. Denomy
C. Fernandes
T. Horton
B. Madrid
S. Murray

ii) The expected gas supply benefits increased due primarily to the assumption that Enbridge would firm up its gas supply portfolio. In other words, Enbridge would increase the amount of long haul firm transportion in its supply portfolio rather than utilize discretionary STFT. This long haul firm transportation would then be displaced with short haul transportation service once the GTA Project Facilities are in service. In terms of Direct Purchase customers Enbridge had assumed that Direct Purchase supplies were entirely sourced at Dawn. The update assumes that a portion of Direct Purchase supplies flow from Empress and that these supplies have been firmed up as well. These Direct Purchase supplies are then assumed to be displaced with short haul firm transportation service once the GTA Project Facilities are in service.

Please see the response to TCPL Interrogatory #3 at Exhibit I.A1.EGD (Update).TCPL.3 for a discussion of why Enbridge has assumed that transportation contracts on the TransCanada system will be firmed up.

iii) The increase in transportation services charge between the 2013-04-15 filing and the current proposal is due to the increase in capital cost and O&M associated with the longer pipeline

iv) Please refer to item (c) i) above.

Witnesses: J. Denomy
C. Fernandes
T. Horton
B. Madrid
S. Murray

Summary Roll-up	WORK BREAKDOWN STRUCTURE Description	Cost Parkway West (Old Location) (NPS 36) Original Application (12/21/12)	Cost Bram West Interconnect (NPS 36) IR Submission (06/07/13)	Cost Bram West Interconnect (NPS 42) Update No. 2 (04/15/13)	Cost Parkway West (New Location) (NPS 42) Update No. 6 (07/22/13)	Variance from Parkway West NPS 36 to: Bram West NPS 36 Option, Bram West NPS 42 Option & Parkway West (New Location) NPS 42
Project Engineering, Development, Execution and Administrative/General						
	Project Development	[redacted]	[redacted]	[redacted]	[redacted]	All Options: Reallocated costs from development accounts to other accounts
	Project Execution	[redacted]	[redacted]	[redacted]	[redacted]	Bram West Options: Increase due to extended execution time period New Pkwy W NPS 42: Ramping up execution team earlier in order to start detailed engineering soon to maintain ISD
	Administrative and General	[redacted]	[redacted]	[redacted]	[redacted]	All Options: Increase due to extended execution time period
	Insurance	[redacted]	[redacted]	[redacted]	[redacted]	All Options: Change in captial costs and updated insurance rates
	Engineering	[redacted]	[redacted]	[redacted]	[redacted]	Bram West Options: Reduction in scope (Parkway West to Bram West) New Pkwy W NPS 42: Additional scope to new Parkway West location (approx 1.5km)
Total Project Engineering, Development, Execution and Administrative/General		[redacted]	[redacted]	[redacted]	[redacted]	
Mainline						
Parkway West or Bram West to Albion		[redacted]	[redacted]	[redacted]	[redacted]	
	Land and Easements	[redacted]	[redacted]	[redacted]	[redacted]	Bram West Options: Reduction in scope (Parkway West to Bram West) New Pkwy W NPS 42: Additional scope to new Parkway West location (approx 1.5km)
	Pipe & Coating	[redacted]	[redacted]	[redacted]	[redacted]	Bram West NPS 36: Reduction in scope (Parkway West to Bram West) Bram West NPS 42: Increase in pipe diameter and WT offset by reduction in scope (Parkway West to Bram West) New Pkwy W NPS 42: Increase in pipe diameter, WT and length to new Parkway West location
	Valves	[redacted]	[redacted]	[redacted]	[redacted]	Bram West NPS 36: Reduction in scope (Parkway West to Bram West) Bram West NPS 42: Increase in pipe diameter and WT offset by reduction in scope (Parkway West to Bram West) New Pkwy W NPS 42: Increase in pipe diameter, WT and length to new Parkway West location
	Induction Bends	[redacted]	[redacted]	[redacted]	[redacted]	Bram West NPS 36: Reduction in scope (Parkway West to Bram West) Bram West NPS 42: Increase in pipe diameter and WT offset by reduction in scope (Parkway West to Bram West) New Pkwy W NPS 42: Increase in pipe diameter, WT and length to new Parkway West location
	Fittings, Flanges, Other	[redacted]	[redacted]	[redacted]	[redacted]	Bram West NPS 36: Reduction in scope (Parkway West to Bram West) Bram West NPS 42: Increase in pipe diameter and WT offset by reduction in scope (Parkway West to Bram West) New Pkwy W NPS 42: Increase in pipe diameter, WT and length to new Parkway West location
	Construction, Testing, Surveys, and Construction Management	[redacted]	[redacted]	[redacted]	[redacted]	Bram West NPS 36: Reduction in scope (Parkway West to Bram West) Bram West NPS 42: Increase in pipe diameter and WT requires more equipment and less productivity New Pkwy W NPS 42: Increase in pipe diameter and WT requires more equipment and less productivity; additional length required to new Parkway W site
	Commissioning & Start-Up	[redacted]	[redacted]	[redacted]	[redacted]	NPS 36: Reduction in scope (Parkway West to Bram West) NPS 42: Increase in pipe diameter
Keele/CNR to Don Valley Junction		[redacted]	[redacted]	[redacted]	[redacted]	
	Land and Easements	[redacted]	[redacted]	[redacted]	[redacted]	No change
	Pipe & Coating	[redacted]	[redacted]	[redacted]	[redacted]	No change
	Valves	[redacted]	[redacted]	[redacted]	[redacted]	No change
	Induction Bends	[redacted]	[redacted]	[redacted]	[redacted]	No change
	Fittings, Flanges, Other	[redacted]	[redacted]	[redacted]	[redacted]	Bram West Options: No change New Pkwy W NPS 42: Slilght increase in updated estimate due to requirement to construct and build hydrostatic test heads - previous estimates assumed rentals would be available
	Construction, Testing, Surveys, and Construction Management	[redacted]	[redacted]	[redacted]	[redacted]	Minor impact due to construction schedule timing and scheduling
	Commissioning & Start-Up	[redacted]	[redacted]	[redacted]	[redacted]	No change
Don Valley Junction to Sheppard Ave		[redacted]	[redacted]	[redacted]	[redacted]	
	Land and Easements	[redacted]	[redacted]	[redacted]	[redacted]	No change
	Pipe & Coating	[redacted]	[redacted]	[redacted]	[redacted]	No change
	Valves	[redacted]	[redacted]	[redacted]	[redacted]	No change
	Induction Bends	[redacted]	[redacted]	[redacted]	[redacted]	No change
	Fittings, Flanges, Other	[redacted]	[redacted]	[redacted]	[redacted]	Bram West Options: No change New Pkwy W NPS 42: Slilght increase in updated estimate due to requirement to construct and build hydrostatic test heads - previous estimates assumed rentals would be available
	Construction, Testing, Surveys, and Construction Management	[redacted]	[redacted]	[redacted]	[redacted]	Minor impact due to construction schedule timing and scheduling
	Commissioning & Start-Up	[redacted]	[redacted]	[redacted]	[redacted]	No change
Total Mainline		[redacted]	[redacted]	[redacted]	[redacted]	
Facilities						
Parkway West Meter Station or Bram West Interconnect		[redacted]	[redacted]	[redacted]	[redacted]	
	Land and Easements	[redacted]	[redacted]	[redacted]	[redacted]	N/A
	Meter Runs	[redacted]	[redacted]	[redacted]	[redacted]	Removed meters at Parkway West from scope of project
	Regulation Runs	[redacted]	[redacted]	[redacted]	[redacted]	N/A
	Heating	[redacted]	[redacted]	[redacted]	[redacted]	N/A
	Odorization	[redacted]	[redacted]	[redacted]	[redacted]	N/A
	Other costs	[redacted]	[redacted]	[redacted]	[redacted]	Bram West Options: Removed all metering scope form Parkway West; Bram West New Pkwy W NPS 42: Site is shared with Parkway West Gate station - civil and electrical infrastructure allocated between both sites
	Construction and Construction Management	[redacted]	[redacted]	[redacted]	[redacted]	mechanical work New Pkwy W NPS 42: Site is shared with Parkway West Gate station - civil and electrical infrastructure allocated between
	Commissioning & Start Up	[redacted]	[redacted]	[redacted]	[redacted]	Bram West Options: Commissioning included in mainline estimate for Bram West to Albion New Pkwy W NPS 42: Commisioning added back into Parkway West site
Parkway West Gate Station and Parkway Bypass Regulation		[redacted]	[redacted]	[redacted]	[redacted]	
	Land and Easements	[redacted]	[redacted]	[redacted]	[redacted]	No change
	Meter Runs	[redacted]	[redacted]	[redacted]	[redacted]	No change
	Regulation Runs	[redacted]	[redacted]	[redacted]	[redacted]	No change
	Heating	[redacted]	[redacted]	[redacted]	[redacted]	No change
	Odorization	[redacted]	[redacted]	[redacted]	[redacted]	half the cost would reside at Parkway West and half would reside at Albion New Pkwy W NPS 42: Assumption of half of cost of odourization due to split in Bram West Options unlikely; more likley full odourization skids will be required at Parkway W and at Albion - full cost of odourization skid included in New Parkway W NPS 42 estimate
	Other costs	[redacted]	[redacted]	[redacted]	[redacted]	Bram West Options: Civil and electrical infrastructure still required for site - all costs allocated to Gate Station New Pkwy W Option: Minor reduction as costs are allocated between the shared facility with Parkway West Initiation Point
	Construction and Construction Management	[redacted]	[redacted]	[redacted]	[redacted]	Bram West Options: Civil and electrical infrastructure still required for site - all costs allocated to Gate Station New Pkwy W Option: Costs are allocated at the shared facility between Parkway West Gate Station and Parkway West Initiation Point
	Commissioning & Start Up	[redacted]	[redacted]	[redacted]	[redacted]	No change
Albion Rd Gate Station		[redacted]	[redacted]	[redacted]	[redacted]	
	Land and Easements	[redacted]	[redacted]	[redacted]	[redacted]	N/A
	Meter Runs	[redacted]	[redacted]	[redacted]	[redacted]	Bram West Options: No change New Pkwy W NPS 42: Additon custody transfer meters included in scope for path to maple
	Regulation Runs	[redacted]	[redacted]	[redacted]	[redacted]	No change
	Heating	[redacted]	[redacted]	[redacted]	[redacted]	No change
	Odorization	[redacted]	[redacted]	[redacted]	[redacted]	half the cost would reside at Parkway West and half would reside at Albion New Pkwy W NPS 42: Assumption of half of cost of odourization due to split in Bram West Options unlikely; more likley full odourization skids will be required at Parkway W and at Albion - full cost of odourization skid included in New Parkway W NPS 42 estimate
	Other costs	[redacted]	[redacted]	[redacted]	[redacted]	All Options: Increase due to added odourization scope and upgrades to metering
	Construction and Construction Management	[redacted]	[redacted]	[redacted]	[redacted]	All Options: Increase due to added odourization scope and upgrades to metering
	Commissioning & Start Up	[redacted]	[redacted]	[redacted]	[redacted]	Bram West Options: No Change New Pkwy W NPS 42: Additional commisioning required for additional meter station
Keele/CNR Feeder Station (Modifications)		[redacted]	[redacted]	[redacted]	[redacted]	
	Land and Easements	[redacted]	[redacted]	[redacted]	[redacted]	N/A
	Meter Runs	[redacted]	[redacted]	[redacted]	[redacted]	N/A
	Regulation Runs	[redacted]	[redacted]	[redacted]	[redacted]	N/A
	Heating	[redacted]	[redacted]	[redacted]	[redacted]	N/A
	Odorization	[redacted]	[redacted]	[redacted]	[redacted]	N/A
	Other costs	[redacted]	[redacted]	[redacted]	[redacted]	No Change
	Construction and Construction Management	[redacted]	[redacted]	[redacted]	[redacted]	All Options: Minor impact due to updated construction schedule and timing
	Commissioning & Start Up	[redacted]	[redacted]	[redacted]	[redacted]	No Change
Buttonville/407 Meter and Regulation Station		[redacted]	[redacted]	[redacted]	[redacted]	
	Land and Easements	[redacted]	[redacted]	[redacted]	[redacted]	No Change
	Meter Runs	[redacted]	[redacted]	[redacted]	[redacted]	No Change
	Regulation Runs	[redacted]	[redacted]	[redacted]	[redacted]	No Change
	Heating	[redacted]	[redacted]	[redacted]	[redacted]	N/A
	Odorization	[redacted]	[redacted]	[redacted]	[redacted]	N/A
	Other costs	[redacted]	[redacted]	[redacted]	[redacted]	No Change
	Construction and Construction Management	[redacted]	[redacted]	[redacted]	[redacted]	All Options: Minor impact due to updated construction schedule and timing
	Commissioning & Start Up	[redacted]	[redacted]	[redacted]	[redacted]	No Change
Jonesville/Eglinton Meter & Reg Station		[redacted]	[redacted]	[redacted]	[redacted]	
	Land and Easements	[redacted]	[redacted]	[redacted]	[redacted]	No Change
	Meter Runs	[redacted]	[redacted]	[redacted]	[redacted]	No Change
	Regulation Runs	[redacted]	[redacted]	[redacted]	[redacted]	No Change
	Heating	[redacted]	[redacted]	[redacted]	[redacted]	N/A
	Odorization	[redacted]	[redacted]	[redacted]	[redacted]	N/A
	Other costs	[redacted]	[redacted]	[redacted]	[redacted]	No Change
	Construction and Construction Management	[redacted]	[redacted]	[redacted]	[redacted]	All Options: Minor impact due to updated construction schedule and timing
	Commissioning & Start Up	[redacted]	[redacted]	[redacted]	[redacted]	No Change
Total Facilities		[redacted]	[redacted]	[redacted]	[redacted]	
Base Project Cost		**$ 501,943,420**	**$ 476,795,013**	**$ 500,563,105**	**$ 548,696,819**	
Contingency		$ 62,240,984	$ 61,983,352	$ 77,964,350	$ 84,471,000	Bram West NPS 36: New risk item identified through ongoing consultation process (increased contingency from 12.4 % to 13.0%) Bram West and New Pkwy W NPS 42 Options: Reduced project definition surrounding NPS 42 option (procurement, working space, productivity)
Base Project Cost and Contingency		$ 564,184,404	$ 538,778,365	$ 578,527,455	$ 633,167,819	
Escalation		$ 27,080,851	$ 25,689,327	$ 27,765,917	$ 33,550,184	Bram West Options: No change in escalation (4.8%) New Pkwy W NPS 42: Updated escalation indices - escalation now 5.3%
Interest During Construction		$ 11,597,123	$ 16,422,098	$ 17,427,559	$ 19,796,321	All Options: Minor increase due to extended schedule
Grand Total		**$ 602,862,379**	**$ 580,889,789**	**$ 623,720,931**	**$ 686,514,324**	

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO CONSUMERS COUNCIL OF CANADA INTERROGATORY #31

INTERROGATORY

A3. Are the costs of the facilities and rate impacts to customers appropriate?

Reference: Ex. A/T2/S1/p. 8

a) Please explain more fully what is meant by a "Financial Backstopping Agreement." What does Enbridge hope to achieve by such an agreement? Has Enbridge previously negotiated any such type of agreement?

b) What will be the impact on the proposal if Enbridge is unable to include Financial Backstopping Agreements with potential shippers?

RESPONSE

a) The development and construction of the Segment A pipeline (referred to as the 'Albion Pipeline' in the open season materials) will benefit both Enbridge's distribution customers as well as any third party shippers. Accordingly, it is reasonable to require third party shippers seeking to benefit from the Albion Pipeline to be allocated an appropriate share of the risk associated with all or a portion of the Albion Pipeline not being constructed as a result of certain conditions precedent (as set forth in the Precedent Agreements to be entered into with shippers) not being satisfied or waived. A copy of the Precedent Agreement and Financial Backstopping agreement can be found in Attachments to I.A1.EGD (Update).BOMA.2.

   Financial Backstopping Agreements are common practice in the industry.

b) The execution of the Financial Backstopping Agreement is an integral part of the agreement for Rate 332 service.

Witness: C. Fernandes

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
CONSUMERS COUNCIL OF CANADA INTERROGATORY #32

INTERROGATORY

A3. Are the costs of the facilities and rate impacts to customers appropriate?

Reference: Ex. E/T1/S1

a) Please provide a sensitivity DCF analysis using all the same assumptions used in the 2013-04-15 filing other than those related to updated tolls and the capital costs related to the change to the Parkway station connection point.

RESPONSE

a) With the exception of updated tolls and the capital costs noted above, the change in the current base case compared to the 2013-04-15 filing is due to the updated customer additions forecast. (Please see 2013-06-03 Update to Exhibit A, Tab 3, Schedule 4). With the change in forecasted number of additions, customer related capital, O&M, volumes and distribution revenues changed correspondingly. As the update to customer additions was a correction to previously filed evidence, the Company does not think it would be beneficial to provide the DCF analysis using the inaccurate forecast.

Witness: S. Murray

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
CONSUMERS COUNCIL OF CANADA INTERROGATORY #33

INTERROGATORY

A3. Are the costs of the facilities and rate impacts to customers appropriate?

Reference: Undertaking JT1.3; A/T3/S9/Attachment 3

Pre-amble – Please refer to Technical Conference Undertaking JT2.13. This interrogatory is seeking to update that response, in the same summary format as at page 2of 2 o that response, and under two different scenarios (1) EGD's toll revenue assumptions (2) 50% of the expected toll revenues.

a) Please provide the following sensitivity analysis in the form of the DCF result summary the following individual and combined assumptions and under two scenarios (1) expected shipper contract toll revenue – i.e. current case; and (2) 50% of expected toll revenues.
   i) 10% increase capital and maintenance costs (E/T1/S1/pg.9);
   ii) 10% reduction in Commodity Prices Assumptions (Table A3);
   iii) 10% reduction in forecast Transportation Savings;
   iv) A reduction of 0.5% in average annual customer (all classes) consumption in each year for the first 25 years of the project;

RESPONSE

Please find below the requested sensitivities.

Please note, item (iv) has been included as requested. However, the economic feasibility assumes costs, average use and distribution revenue rates are held constant in current year terms over the 40 year horizon.

Witnesses: J. Denomy
S. Murray

I.A3.EGD (Update).CCC.33a(1)

Column #	1	2	3	4	5	6
Document Type:	**Evidence**	**IR**	**IR**	**IR**	**IR**	**IR**
Scenario Description:	Current Base Case **42''**	(i) 10% increase in Capex **42"**	(ii) 10% reduction in Commodity Prices Assumptions **42''**	(iii) 10% reduction in Transporation Savings **42''**	(iv) 0.5% reduction in average annual customer consumption **42"**	(i) to (iv) combined **42"**
Filed Date:	7/22/2013	8/12/2013	8/12/2013	8/12/2013	8/12/2013	8/12/2013
Reference:	Ex. E, Tab 1, Sch. 1	CCC-33.a.1.i	CCC-33.a.1.ii	CCC-33.a.1.iii	CCC-33.a.1.iv	CCC-33.a.1.i to iv
Capital Investment						
Total Upfront Capital	$652,144,124	$717,358,537	$652,144,124	$652,144,124	$652,144,124	$717,358,537
Future Reinforcement Projects						
2017	$21,000,000	$23,100,000	$21,000,000	$21,000,000	$21,000,000	$23,100,000
2018	$16,400,000	$18,040,000	$16,400,000	$16,400,000	$16,400,000	$18,040,000
2019	$13,000,000	$14,300,000	$13,000,000	$13,000,000	$13,000,000	$14,300,000
2020	$250,000	$275,000	$250,000	$250,000	$250,000	$275,000
Capital Maintenance Costs[1]	$5,230,240	$5,753,264	$5,230,240	$5,230,240	$5,230,240	$5,753,264
Services[2]	$379,533,696	$417,487,066	$379,533,696	$379,533,696	$379,533,696	$417,487,066
Total Capital	$1,087,558,060	$1,196,313,866	$1,087,558,060	$1,087,558,060	$1,087,558,060	$1,196,313,866
Total Transportation Savings[1,3]	$1,732,650,739	$1,732,650,739	$1,802,550,575 [5]	$1,559,385,665	$1,732,650,739	$1,622,295,517 [6]
Total Transportation Services Charge[1,4]	$471,256,624	$517,377,889	$471,256,624	$471,256,624	$471,256,624	$517,377,889
Total Distribution Revenues[1]	$4,546,724,222	$4,546,724,222	$4,546,724,222	$4,546,724,222	$4,147,019,522	$4,147,019,522
Total Customer Additions (2015 - 2024)	146,337	146,337	146,337	146,337	146,337	146,337
Total Volumes (10^3m^3)	24,709,032	24,709,032	24,709,032	24,709,032	22,537,605	22,537,605
SUMMARY OF RESULTS						
Net Present Value (40 years)	$667,432,377	$600,770,866	$701,942,955	$581,934,923	$626,470,825	$505,371,381
Variance to Current Base Case NPV (40 years)		($66,661,511)	$34,510,579	($85,497,454)	($40,961,552)	($162,060,995)
Profitability Index (40 years)	1.73	1.60	1.77	1.64	1.69	1.50

NOTES:

[1]Total for the 40 year horizon of analysis.
[2]Services include the costs for distribution mains, services and meters based on the 2013 capital budget.
[3]Total transportation savings are equal to expected gas supply benefits and incorporate the total cost of landing gas in the Enbridge franchise area including costs associated with tolls, fuel and commodity procurement (i.e. basis differentials). Prepared with TransCanada tolls based on the NEB's Toll Order TG-006-2013 (issued June 11, 2013) which made TransCanada's Compliance Filing tolls final and effective July 1, 2013
[4]Transportation Services Charges to be received from contracted shippers for transportation from Parkway West to Albion. (Current Base Case)
[5]The 10% reduction in commodity prices effectively reduces basis which increases the expected gas supply benefits relative to the base case
[6]Result of combination of (ii) and (iii) - 10% reduction of transporation savings based on $1,802.6MM

Witnesses: J. Denomy
S. Murray

I.A3.EGD (Update).CCC.33a(2)

Column #	1	2	3	4	5	6	7
Document Type:	**Evidence**	**IR**	**IR**	**IR**	**IR**	**IR**	**IR**
Scenario Description:	Current Base Case **42''**	Current Base Case with 50% Transportation Services Charge **42''**	(i) 10% increase in Capex **42"**	(ii) 10% reduction in Commodity Prices Assumptions **42''**	(iii) 10% reduction in Transporation Savings **42''**	(iv) 0.5% reduction in average annual customer consumption **42"**	(i) to (iv) combined **42"**
Filed Date:	7/22/2013	8/12/2013	8/12/2013	8/12/2013	8/12/2013	8/12/2013	8/12/2013
Reference:	Ex. E, Tab 1, Sch. 1	CCC-33.a.2	CCC-33.a.2.i	CCC-33.a.2.ii	CCC-33.a.2.iii	CCC-33.a.2.iv	CCC-33.a.2.i to iv
Capital Investment							
Total Upfront Capital	$652,144,124	$652,144,124	$717,358,537	$652,144,124	$652,144,124	$652,144,124	$717,358,537
Future Reinforcement Projects							
2017	$21,000,000	$21,000,000	$23,100,000	$21,000,000	$21,000,000	$21,000,000	$23,100,000
2018	$16,400,000	$16,400,000	$18,040,000	$16,400,000	$16,400,000	$16,400,000	$18,040,000
2019	$13,000,000	$13,000,000	$14,300,000	$13,000,000	$13,000,000	$13,000,000	$14,300,000
2020	$250,000	$250,000	$275,000	$250,000	$250,000	$250,000	$275,000
Capital Maintenance Costs[1]	$5,230,240	$5,230,240	$5,753,264	$5,230,240	$5,230,240	$5,230,240	$5,753,264
Services[2]	$379,533,696	$379,533,696	$417,487,066	$379,533,696	$379,533,696	$379,533,696	$417,487,066
Total Capital	$1,087,558,060	$1,087,558,060	$1,196,313,866	$1,087,558,060	$1,087,558,060	$1,087,558,060	$1,196,313,866
Total Transportation Savings[1,3]	$1,732,650,739	$1,732,650,739	$1,732,650,739	$1,802,550,575 [5]	$1,559,385,665	$1,732,650,739	$1,622,295,517 [6]
Total Transportation Services Charge[1,4]	$471,256,624	$235,628,312	$258,688,944	$235,628,312	$235,628,312	$235,628,312	$258,688,944
Total Distribution Revenues[1]	$4,546,724,222	$4,546,724,222	$4,546,724,222	$4,546,724,222	$4,546,724,222	$4,147,019,522	$4,147,019,522
Total Customer Additions (2015 - 2024)	$146,337	146,337	146,337	146,337	146,337	146,337	146,337
Total Volumes (10^3m^3)	$24,709,032	24,709,032	24,709,032	24,709,032	24,709,032	22,537,605	22,537,605
SUMMARY OF RESULTS							
Net Present Value (40 years)	$667,432,377	$588,387,488	$513,949,658	$622,898,067	$502,890,034	$547,425,936	$418,550,173
Variance to Current Base Case NPV (40 years)		($79,044,889)	($153,482,719)	($44,534,310)	($164,542,342)	($120,006,441)	($248,882,203)
Profitability Index (40 years)	1.73	1.65	1.51	1.68	1.55	1.60	1.42

NOTES:

[1]Total for the 40 year horizon of analysis.

[2]Services include the costs for distribution mains, services and meters based on the 2013 capital budget.

[3]Total transportation savings are equal to expected gas supply benefits and incorporate the total cost of landing gas in the Enbridge franchise area including costs associated with tolls, fuel and commodity procurement (i.e. basis differentials). Prepared with TransCanada tolls based on the NEB's Toll Order TG-006-2013 (issued June 11, 2013) which made TransCanada's Compliance Filing tolls final and effective July 1, 2013

[4]Transportation Services Charges to be received from contracted shippers for transportation from Parkway West to Albion. (Current Base Case)

[5]The 10% reduction in commodity prices effectively reduces basis which increases the expected gas supply benefits relative to the base case

[6]Result of combination of (ii) and (iii) - 10% reduction of transporation savings based on $1,802.6MM

Witnesses: J. Denomy
S. Murray

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
CANADIAN MANUFACTURERS & EXPORTERS INTERROGATORY #1

INTERROGATORY

Issue: A3

Are the costs of the facilities and rate impacts to customers appropriate?

Ref: Exhibit A, Tab 3, Schedule 9, pages 2-4

Preamble

EGD's updated evidence acknowledges that there exists a "dependency" on Segment A for transportation benefits along the Parkway to Maple path. CME understands that these transportation benefits could flow to Ontario ratepayers outside of EGD's distribution area, in particular, in Union North.

Questions

CME wishes to better understand the potential rate impacts that these dependent transportation benefits may have on Ontario ratepayers. Within this context:

(a) Has EGD undertaken any analysis, including an economic feasibility analysis, of the "dependent transportation benefits"? If so, please provide a copy of the analysis. If no analysis has been conducted, please explain why not.

(b) In Exhibit M.TCPL.CME.l, TCPL provided its analysis of:

   (i) the potential consequential impact long-term on all TCPL tolls paid by Ontario gas users as a result ofTCPL's loss oflong-haul revenue;

   (ii) the additional cost that Ontario gas users will incur as a result of constructing facilities to accommodate new short-haul capacity; and

(c) The savings that Ontario gas consumers could realize by sourcing more gas through short-haul transportation services.

Does EGD agree with TCPL's analysis? If not, please explain which aspects of the analysis EGD disagrees with.

Witness: J. Denomy

RESPONSE

a) No, Enbridge has not conducted any analysis or economic analysis of the dependent transportation benefits associated with a complete build out of the Parkway to Maple path. The primary focus of the GTA Project has been the distribution needs of customers in the GTA Project Influence Area. Completing the Parkway to Maple path and increased market access has the potential to create transportation benefits to all downstream markets including Enbridge's customers in the Ottawa area. Enbridge expects to conduct an analysis once sufficient information is available on TransCanada tolls associated with creating market access for these downstream markets. The rate impacts on Ontario ratepayers are dependent not only on resolution of the tolling issue but the availability of sufficient capacity to meet gas needs as a result of redeployment of gas facilities to oil. Please also see the response to IGUA #1 at Exhibit I.A1.EGD (Update).IGUA.1.

b) and c) Enbridge agrees with TransCanada's analysis to the extent that the calculations appear to be correct based on the assumptions made. Enbridge would disagree with TransCanada's suggestion that recent basis differential between Empress and Dawn of $1.50/GJ is representative of what can be expected to prevail indefinitely. Recent basis values between Empress and Dawn are reflective of TransCanada's exercise of pricing discretion and will have consequential market impacts such as lower reliance on services that TransCanada has pricing discretion over and/or concomitant changes in production and exports from Western Canada and the emerging supply basins. Enbridge expects these basis values will be transitory and not sustainable over the long term. In addition, TransCanada's analysis does not incorporate the costs associated with sourcing year round long haul transport for meeting seasonal needs.

Witness: J. Denomy

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
CANADIAN MANUFACTURERS & EXPORTERS INTERROGATORY #2

INTERROGATORY

Issue: A3

Are the costs of the facilities and rate impacts to customers appropriate?

Ref: Exhibit A, Tab 2, Schedule 4, page 5 of 9

Preamble
It is CME's understanding that the Memorandum of Understanding ("MOU") between EGD and TCPL was terminated by EGD. TCPL filed a letter with the Board on July 24, 2013 which confirmed TCPL's position that the MOU remains a valid and binding contract.

Questions
If TCPL is correct, and the MOU remains a valid and binding contract, what are the potential cost consequences for EGD's customers, if any?

Without limiting the generality of this question, please address whether the cost consequences of a breach of the MOU by EGD would flow directly to EGD's shareholder or, in part or in whole, to EGD's customers?

RESPONSE

Please see response to CCC Interrogatory #28 found at Exhibit I.A1.EGD (Update).CCC.28.

Witness: M. Giridhar

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENVIRONMENTAL DEFENCE INTERROGATORY #44

INTERROGATORY

Issue A.3 “Are the costs of the facilities and rate impacts to customers appropriate?”

Reference: Ex. A, Tab 3, Schedule 9, Attachment 3

Please reproduce this exhibit assuming the time horizon for calculating the “Total Transportation Savings” and “Total Transportation Services Charge” revenues is limited to the 2015 to 2024 time period.

RESPONSE

For clarity, the original exhibits included upstream “Total Transportation Savings” for the period of 2015 to 2025, with 2015 being a partial year due to the gas year start in November.

The “Total Transportation Services Charge” represents the toll revenue from the transportation service. The initial contracts will be for a 15 year duration as per I.A1.EGD (Update).BOMA.2. The Company therefore views a scenario with less than 15 years, as has been requested, to be unrealistic.

However, the results are presented below. In all scenarios the project is feasible.

Witness: S. Murray

Column #	1	2	3	4	5	6
Document Type:	IR	IR	IR	IR	IR	IR
Scenario Description:	ED-44 Resulting Base Case **42''**	ED44 Base Case with 75% Transportation Savings **42"**	ED44 Base Case with 50% Transportation Savings **42''**	ED44 Base Case with 0% Transportation Services Charges **42''**	ED44 Base Case with No Customer Additions **42"**	ED44 Base Case with 10% Increase in Capital Cost **42"**
Filed Date:	8/12/2013	8/12/2013	8/12/2013	8/12/2013	8/12/2013	8/12/2013
Reference:	ED-44	ED-44	ED-44	ED-44	ED-44	ED-44
Capital Investment						
Total Upfront Capital	$652,144,124	$652,144,124	$652,144,124	$652,144,124	$652,144,124	$717,358,537
Future Reinforcement Projects						
2017	$21,000,000	$21,000,000	$21,000,000	$21,000,000	$0	$23,100,000
2018	$16,400,000	$16,400,000	$16,400,000	$16,400,000	$0	$18,040,000
2019	$13,000,000	$13,000,000	$13,000,000	$13,000,000	$0	$14,300,000
2020	$250,000	$250,000	$250,000	$250,000	$0	$275,000
Capital Maintenance Costs[1]	$5,230,240	$5,230,240	$5,230,240	$5,230,240	$5,230,240	$5,753,264
Services[2]	$379,533,696	$379,533,696	$379,533,696	$379,533,696	$0	$417,487,066
Total Capital	$1,087,558,060	$1,087,558,060	$1,087,558,060	$1,087,558,060	$657,374,364	$1,196,313,866
Total Transportation Savings[3] (2015-2024)	$1,561,635,909	$1,171,226,931	$780,817,954	$1,561,635,909	$1,561,635,909	$1,561,635,909
Total Transportation Services Charge[4] (2015 - 2024)	$175,104,348	$175,104,348	$175,104,348	$0	$175,104,348	$192,392,044
Total Distribution Revenues[1]	$4,546,724,222	$4,546,724,222	$4,546,724,222	$4,546,724,222	$0	$4,546,724,222
Total Customer Additions (2015 - 2024)	146,337	146,337	146,337	146,337	-	146,337
Total Volumes (10^3m^3)	24,709,032	24,709,032	24,709,032	24,709,032	-	24,709,032
SUMMARY OF RESULTS						
Net Present Value (40 years)	$534,351,214	$336,622,917	$138,894,620	$445,281,250	$316,735,228	$460,933,849
Variance to ED.44 Base Case NPV (40 years)		($197,728,297)	($395,456,594)	($89,069,964)	($217,615,985)	($73,417,365)
Profitability Index (40 years)	1.59	1.37	1.15	1.49	1.52	1.46

NOTES:

[1]Total for the 40 year horizon of analysis.

[2]Services include the costs for distribution mains, services and meters based on the 2013 capital budget.

[3]Total transportation savings are equal to expected gas supply benefits and incorporate the total cost of landing gas in the Enbridge franchise area including costs associated with tolls, fuel and commodity procurement (i.e. basis differentials) Prepared with TransCanada tolls based on the NEB's Toll Order TG-006-2013 (issued June 11, 2013) which made TransCanada's Compliance Filing tolls final and effective July 1, 2013

[4]Transportation Services Charges to be received from contracted shippers for transportation from Parkway West to to Albion. (Current Base Case)

Witness: S. Murray

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENVIRONMENTAL DEFENCE INTERROGATORY #45

INTERROGATORY

Issue A.3 "Are the costs of the facilities and rate impacts to customers appropriate?"

Reference: Ex. A, Tab 3, Schedule 9, Attachment 3

Please provide a break-out of the current base case "Total Transportation Savings" of $1.73 billion according to the following categories: a) transportation tolls; b) commodity costs.

RESPONSE

Please see Table A5 found in Exhibit A, Tab 3, Schedule 9, Attachment 1, page 5. Table A5 provides a complete break-out of the expected transportation savings by service, path, contract demand, demand charges (i.e. transportation tolls), fuel charges, and commodity costs for the current base case. The bottom row, "Savings (A-B)", sums to $1.73 billion.

Witness: J. Denomy

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENVIRONMENTAL DEFENCE INTERROGATORY #46

INTERROGATORY

Issue A.3 “Are the costs of the facilities and rate impacts to customers appropriate?”

Reference: Ex. A, Tab 3, Schedule 9, Attachment 3

Please reproduce this exhibit with the following new assumptions:

a) The addition of in-franchise customer additions (146,337) in the GTA Project Influence Area between 2015 and 2024 is accompanied by no net growth in total annual throughput volumes or peak demand in the GTA Project Influence Area. That is, Enbridge’s net incremental “Total Distribution Revenues” is equal to the incremental fixed monthly customer charge revenues associated with the incremental customers; and

b) The time horizon for calculating the “Total Transportation Savings” and “Total Transportation Services Charge” revenues is limited to the 2015 to 2024 time period.

RESPONSE

a) The economic feasibility assumes costs, average use and distribution revenue rates are held constant in current year terms over the 40 year horizon.

b) Please see response to Environmental Defence Interrogatory #44 found at Exhibit I.A.3.EGD (Update).ED.44.

Witness: S. Murray

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENVIRONMENTAL DEFENCE INTERROGATORY #47

INTERROGATORY

Issue A.3 “Are the costs of the facilities and rate impacts to customers appropriate?”

Reference: Ex. E, Tab 1, Schedule 2, Page 2

Enbridge is forecasting that 60% of the Albion Pipeline will be used by ex-franchise transportation customers. Nevertheless, Enbridge is proposing that if the Pipeline has no exfranchise transportation customers, “distribution ratepayers will be allocated the entire revenue requirement”.

Please explain why Enbridge believe that the risk associated with unused ex-franchise transportation pipeline capacity should be borne by its in-franchise distribution customers as opposed to its shareholder?

RESPONSE

Enbridge does not agree that the risk associated with unused ex-franchise transportation capacity is being borne by its distribution customers. Enbridge is proposing to calculate Rate 332 based on 60% of the revenue requirement of the Albion Pipeline divided by ex-franchise contract demand volumes. As such the risk of unused transmission capacity is borne by ex-franchise transportation customers through higher Rate 332 charges.

In the event that no shippers take transmission service, Enbridge has determined that the NPS 42 size for the Albion pipeline is required to meet its distribution needs of 800 TJ/d in the GTA, in conjunction with an inlet pressure of 530 psi which is in line with operating pressures of other distribution pipelines (Please also see Exhibit I.A3.EGD (Update).TCPL.24). Alternatively, in conjunction with higher inlet pressures and downstream facilities, the NPS 42 pipe size allows for significant economies of scale that would allow for 60% of the revenue requirement to be borne by shippers, and thereby allowing distribution customers to receive the needed 800 TJ/d of supply at only 40% of the revenue requirement of the Albion Pipeline.

The project facilities are required to meet the needs of distribution customers, and distribution customers will see the benefits of the facilities. As shown in the Economic Sensitivity in Exhibit A, Tab 3, Schedule 9, Attachment 3, even with no transmission shippers on the Albion line, the project is feasible and a benefit to distribution ratepayers.

Witness: M. Giridhar

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO ENVIRONMENTAL DEFENCE INTERROGATORY #48

INTERROGATORY

Issue A.3 “Are the costs of the facilities and rate impacts to customers appropriate?”

Reference: Ex. E, Tab 1, Schedule 2 including Attachment 2

Please state the minimum contract term for a Rate 332 transportation service customer.

RESPONSE

The minimum initial contract term for Rate 332 transportation service on the Albion Pipeline is 15 years.

Witness: M. Giridhar

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENVIRONMENTAL DEFENCE INTERROGATORY #49

INTERROGATORY

Issue A.3 “Are the costs of the facilities and rate impacts to customers appropriate?”

Reference: Ex. A, Tab 3, Schedule 9, Attachment 3

Please provide a break-out of the current base case “Total Transportation Savings” according to the following categories: a) Enbridge in-franchise Ontario consumers; b) other Ontario consumers; and c) non-Ontario consumers.

RESPONSE

The Total Transportation Savings are the same as the Expected Gas Supply Benefits. The Expected Gas Supply Benefits would accrue to both Enbridge’s System Gas customers and Direct Purchase customers. These benefits are provided at Exhibit A, Tab 3, Schedule 9, page 9.

Witness: J. Denomy

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENVIRONMENTAL DEFENCE INTERROGATORY #50

INTERROGATORY

Issue A.3 “Are the costs of the facilities and rate impacts to customers appropriate?”

Reference: Ex. A, Tab 3, Schedule 9, Attachment 3

A recent Globe and Mail article reported that Alberta natural gas is selling at a deep discount as compared to gas from the United States priced at Henry Hub. The article, which is provided as an attachment to this interrogatory, reported that:

> “The discount on natural gas prices in Alberta compared with Henry Hub, La., the pricing point for U.S. gas futures, has widened by 86 per cent in the last two months.
>
> Alberta gas for August delivery is selling for about $2.48 per gigajoule, down 25 per cent from the beginning of June. At Henry Hub, the equivalent amount of gas sells for about $3.50.”

It does not appear that the higher gas commodity costs associated with purchasing gas from the U.S. north east is accounted for in the calculations appearing at Ex. A, Tab 3, Schedule 9, Attachment 3.

a) Please indicate whether the higher commodity cost of Alberta gas as compared to gas from the United States is accounted for in the calculations appearing at Ex. A, Tab 3, Schedule 9, Attachment 3.

b) Please reproduce the calculations appearing at Ex. A, Tab 3, Schedule 9, Attachment 3 to include the present value of the forecast net gas cost savings (lower transportation tolls *plus higher gas commodity costs*) due to the GTA Pipeline assuming the following time horizons: a) 2015 to 2024; and b) 40 years. Please state the assumed natural gas throughput volumes for each year.

c) Please reproduce the above calculation on the assumption that gas from the United States (at Henry Hub) continues to sell at a 40% premium vis-à-vis the cost of Alberta gas.

Witnesses: J. Denomy
S. Murray

d) Please provide a table with an estimate of the natural gas commodity cost as priced at the AECO-C (Alberta) and at Henry Hub (United States) from 2012 to 2024. Please account for the impact on the Alberta price of the recent increases in the cost of moving natural gas to Ontario and Quebec via TransCanada Corp. Please explain and justify the estimates provided.

RESPONSE

a) For a discussion and sensitivity analysis of the impact of basis differentials on the expected gas supply benefits please refer to the response to TCPL Interrogatory #2 at Exhibit I.A1.EGD (Update).TCPL.2.

b) The base case forecast includes commodity forecasts per supply basin plus transportation. Please refer to Exhibit A, Tab 3, Schedule 9, Attachment 1, page 3 for commodity assumptions and page 1 for toll assumptions.

   The base case assumes transportation savings for the period 2015 to 2025. For feasibility purposes, the amounts beyond 2025 have been assumed to be zero for conservatism. Reproducing the economics based on period of 2015 to 2024 instead of a period of 2015 to 2025 is burdensome and will not yield much new information. Reproducing the economics based on 40 years, as compared to the conservation assumption of zero savings beyond 2025 will only show an increase in the benefits of a project that is already well above feasible. This demonstrates that the project is beneficial to ratepayers.

   Natural gas throughput volumes (average and cumulative) are shown in Exhibit E, Tab 1, Schedule 1, page 8.

c) Please see a) for the impact of basis differentials.

d) Please refer to Exhibit A, Tab 3, Schedule 9, Attachment 1, page 3 for commodity assumptions and page 1 for toll assumptions.

Witnesses: J. Denomy
S. Murray

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
ENERGY PROBE RESEARCH FOUNDATION INTERROGATORY #92

INTERROGATORY

Issue A3 - Are the costs of the facilities and rate impacts to customers appropriate?

Ref: EB-2012-0451 Exhibit A, Tab 3 Schedule 9 pages 15-16

a) Please confirm the bill impacts are for the new base case and confirm assumptions related to annual revenue requirement(s)

b) Please provide the average residential bill impacts for Segment A for each of
   i. 36 " EGD sole use pipeline
   ii. 36" EGD plus 400 Gj/d other shippers
   iii. 42" EGD plus 800 Gj/d other shippers
   iv. 42" EGD plus 1200 Gj/d other shippers

RESPONSE

a) The rate impacts depicted at Exhibit A, Tab 3, Schedule 9, pages 15 and 16 are based on NPS 42 pipeline from Parkway to Albion as filed in the Company's updated evidence on July 22, 2013. The rate impacts are based on the proposed 2016 revenue requirement for the proposed base case.

b) i) The Company is no longer proposing a 36" pipeline however, for purposes of this interrogatory the previous base case filed at Exhibit JT2.16 on June 18, 2013 assumed a 36" pipeline from Bram West to Albion. Assuming the entire cost of the GTA project based on 36" pipeline is recovered from EGD's customers, the bill impacts inclusive of gas cost savings would be:

		BUNDLED RATES	
Rate Class		Sales Service	
1		-1.8%	
6		-2.9%	
9		-4.0%	
100		-5.4%	
110		-5.4%	
115		-6.0%	
135		-6.6%	
145		-5.8%	
170		-6.9%	
200		-4.2%	
		UNBUNDLED RATES	
125		23.9%	
300		8.7%	

ii) The Company is proposing that the entire cost of the transportation portion of Segment A pipeline be recovered from transportation shippers. However, for purposes of this interrogatory response the Company has assumed that the allocation of costs between EGD's customers and shippers would be based on transportation shippers using 400 TJ/day. Based on the response to part b) i) above and assuming 400 TJ/day is allocated to shippers, the bill impacts inclusive of gas costs savings would be:

		BUNDLED RATES	
Rate Class		**Sales Service**	
1		-2.0%	
6		-3.1%	
9		-4.1%	
100		-5.6%	
110		-5.6%	
115		-6.2%	
135		-6.8%	
145		-6.0%	
170		-7.1%	
200		-4.4%	
		UNBUNDLED RATES	
125		23.9%	
300		8.7%	

iii) The Company is proposing that the entire cost of the transportation portion of Segment A pipeline be recovered from transportation shippers. However, for purposes of this interrogatory response the Company has assumed that the allocation of costs between EGD's customers and shippers would be based on Shippers using 800 TJ/day. Based on the Company's current base case as filed on July 22, 2013, assuming a 42" pipeline from Parkway to Albion with 800TJ/day allocated to shippers, the bill impacts inclusive of gas costs savings would be:

		BUNDLED RATES	
Rate Class		**Sales Service**	
1		-1.9%	
6		-3.0%	
9		-4.1%	
100		-5.5%	
110		-5.5%	
115		-6.1%	
135		-6.7%	
145		-5.9%	
170		-7.0%	
200		-4.3%	
		UNBUNDLED RATES	
125		23.5%	
300		8.6%	

iv) This scenario reflects the Company's current base case proposal, the bill impacts inclusive of gas costs savings are the same as those outlined in Exhibit A, Tab 3, Schedule 9, page 16 and are shown below:

		BUNDLED RATES	
Rate Class		**Sales Service**	
1		-2.2%	
6		-3.3%	
9		-4.2%	
100		-5.7%	
110		-5.7%	
115		-6.3%	
135		-6.9%	
145		-6.1%	
170		-7.3%	
200		-4.6%	
		UNBUNDLED RATES	
125		23.5%	
300		8.6%	

Witness: A. Kacicnik

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
LPMA INTERROGATORY #1

INTERROGATORY

Issue A3. Are the costs of the facilities and rate impacts to customers appropriate?

Ref: Exhibit A, Tab 2, Schedule 1, para. 6

What is the estimated annual cost of the land leased from Union Gas at the proposed Parkway West Station?

RESPONSE

Enbridge has had initial discussions with Union Gas and there is agreement from both parties that the land required by Enbridge for their Parkway West Station will be leased from Union Gas. Further discussions and negotiations on lease costs are underway and will continue once Enbridge is able to proceed with detail engineering of the facilities to confirm final land requirements.

Witness: B. Madrid

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
SEC INTERROGATORY #26

INTERROGATORY

Issue A3

[Ex. A/3/9/3]

Please provide the Economic Sensitivity Results in the format set out in Ex. A, Tab 3, Schedule 9, Attachment 3, for a 36" pipe size Base Case.

RESPONSE

Please see the table below.

Witness: S. Murray

Column #	1	2
Document Type:	**Evidence**	**IR**
Scenario Description:	Current Base Case **42''**	36" Pipe Size **36"**
Filed Date:	7/22/2013	8/12/2013
Reference:	Ex. E, Tab 1, Sch. 1	SEC 26

Capital Investment

Total Upfront Capital [5]	$652,144,124	$604,184,399
Future Reinforcement Projects		
2017	$21,000,000	$21,000,000
2018	$16,400,000	$16,400,000
2019	$13,000,000	$13,000,000
2020	$250,000	$250,000
Capital Maintenance Costs [1]	$5,230,240	$4,051,240
Services [2]	$379,533,696	$379,533,696
Total Capital	$1,087,558,060	$1,038,419,335
Total Transportation Savings [1,3]	$1,732,650,739	$1,732,650,739
Total Transportation Services Charge [1,4]	$471,256,624	$334,753,400
Total Distribution Revenues [1]	$4,546,724,222	$4,546,724,222
Total Customer Additions (2015 - 2024)	146,337	146,337
Total Volumes ($10^3 m^3$)	24,709,032	24,709,032
SUMMARY OF RESULTS		
Net Present Value (40 years)	$667,432,377	$662,236,409
Profitability Index (40 years)	1.73	1.76

NOTES:

[1] Total for the 40 year horizon of analysis.

[2] Services include the costs for distribution mains, services and meters based on the 2013 capital budget.

[3] Total transportation savings are equal to expected gas supply benefits and incorporate the total cost of landing gas in the Enbridge franchise area including costs associated with tolls, fuel and commodity procurement (i.e. basis differentials). Prepared with TransCanada tolls based on the NEB's Toll Order TG-006-2013 (issued June 11, 2013) which made TransCanada's Compliance Filing tolls final and effective July 1, 2013

[4] Transportation Services Charges to be received from contracted shippers for transportation from Parkway West to Albion. (Current Base Case)

[5] Enbridge did not perform a detailed cost estimate for this alternative, but developed a high level ranged estimate for this response and I.D5.EGD(Update).EP.101.

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
TCPL INTERROGATORY #23

INTERROGATORY

Issue A3

Reference(s) (i) Exhibit A, Tab 3, Schedule 6

Preamble
TransCanada would like to understand the differences in capital and resulting annual revenue requirements and tolls for the various options for a Segment A build.

Request
(a) Please provide, in a summary table, what the total capital costs and associated resulting capacity (in TJs/day) would be for Segment A if it were built as:
(i) Parkway to Albion at NPS 24 pipe size
(ii) Parkway to Albion at NPS 30 pipe size
(iii) Parkway to Albion at NPS 36 pipe size
(iv) Parkway to Albion at NPS 42 pipe size
(v) Bram West to Albion at NPS 24 pipe size
(vi) Bram West to Albion at NPS 30 pipe size
(vii) Bram West to Albion at NPS 36 pipe size
(viii) Bram West to Albion at NPS 42 pipe size

When providing this information, please differentiate the capital costs for each option into separate line items for pipe, compression, metering, odorization, and any other capital costs, as well as grand totals.

(b) Are there any other build options that EGD has been considering for Segment A? If so, please describe these options and provide each of those options as well in the summary table for response (a).

(c) Please confirm the in service date for all of these scenarios in response (a) and (b) would be November 1, 2015. If not confirmed, please provide the in service dates

Witnesses: K. Culbert
C. Fernandes
T. Horton
A. Kacicnik
S. Murray

for each scenario in response (a) and (b), and explain why the dates are not the same in all scenarios.

(d) For each of the Segment A build options (i) through (viii) in question (a) above, and any other build options considered by EGD in response (b) above, please provide the detailed annual rate base and annual revenue requirement calculations (by individual cost item) for each year of 15 years starting at the November 1, 2015 in service date. The annual revenue requirement calculations should provide separate line items for all expected costs associated with these facilities, including but not limited to depreciation expense, debt return, equity return, income tax, operations and maintenance, pipeline integrity costs, municipal and other taxes. Also please provide all the assumptions used in these calculations, such as depreciation rates for each type of facilities, income tax rate, CCA rate, return on equity %, debt rate, debt to equity ratio, and any escalation factors or inflation rates used.

(e) For each of the Segment A build options (i) through (viii) in question (a) above, and any other build options considered by EGD in response (b) above, and using the annual revenue requirements in (d) above, please provide the resulting annual tolls for Segment A in each year for 15 years starting November 1, 2015 if:

(i) Only 800 TJ/d of Segment A capacity is subscribed by EGD
(ii) All of Segment A capacity is subscribed (i.e. 800 TJ/d by EGD is subscribed and remaining capacity is fully subscribed by other shippers).

<u>RESPONSE</u>

(a) (i) Parkway to Albion at NPS 24 pipe size
Not evaluated – never a valid option for consideration

(ii) Parkway to Albion at NPS 30 pipe size
Not evaluated – never a valid option for consideration

(iii) Parkway to Albion at NPS 36 pipe size
Approximate factored cost estimate to new Parkway West site $615-655M
NPS 36 capacity: 1,600 TJ/day

Witnesses: K. Culbert
C. Fernandes
T. Horton
A. Kacicnik
S. Murray

*Estimate is factored and provided as rough order of magnitude – detailed breakdown not available.

(iv) Parkway to Albion at NPS 42 pipe size
Please see the attachment to the confidential response to CCC Interrogatory #30 at Exhibit I.A3.EGD(Update).CCC.30 for costs.
NPS 42 capacity: 2,000 TJ/d

(v) Bram West to Albion at NPS 24 pipe size
Not evaluated – never a valid option for consideration

(vi) Bram West to Albion at NPS 30 pipe size
Not evaluated – never a valid option for consideration

(vii) Bram West to Albion at NPS 36 pipe size
Please see the attachment to the confidential response to CCC Interrogatory #30 at Exhibit I.A3.EGD (Update).CCC.30.
NPS 36 capacity: 1,600 TJ/d

(viii) Bram West to Albion at NPS 42 pipe size
Please see the attachment to the confidential response to CCC Interrogatory #30 at Exhibit I.A3.EGD (Update).CCC.30.
NPS 42 capacity: 2,000 TJ/d

(b) No other options were evaluated for Segment A.

(c) Confirmed.

(d) (i) Parkway to Albion at NPS 24 pipe size
Not evaluated – never a valid option for consideration

(ii) Parkway to Albion at NPS 30 pipe size
Not evaluated – never a valid option for consideration

Witnesses: K. Culbert
C. Fernandes
T. Horton
A. Kacicnik
S. Murray

(iii) Parkway to Albion at NPS 36 pipe size
Please see attached table.

(iv) Parkway to Albion at NPS 42 pipe size
Please see attached table.

(v) Bram West to Albion at NPS 24 pipe size
Not evaluated – never a valid option for consideration

(vi) Bram West to Albion at NPS 30 pipe size
Not evaluated – never a valid option for consideration

(vii) Bram West to Albion at NPS 36 pipe size
Please see attached table.

(viii) Bram West to Albion at NPS 42 pipe size
Please see attached table.

Please refer to Exhibit I.A3.EGD.STAFF.16a for the capital structure.

Please refer to Exhibit E, Tab 1, Schedule 1, pages 8 and 9 and Exhibit E, Tab 1, Schedule 1, Attachment, page 1 for the input parameters.

(e) Note that with respect to the proposed Rate 332 transportation service, Enbridge is asking within this application for approval of the proposed Rate 332 transportation service and the methodology that will be applied to develop the Contract Demand (CD) charge for Rate 332 transportation service. Enbridge is not seeking approval of a specific Contract Demand (CD) charge for Rate 332 transportation service within this application. Enbridge will ask for such an approval with an annual rate adjustment application.

i) This question assumes there are no shippers for the transportation service under Rate 332. As per the updated evidence at Exhibit E, Tab 1, Schedule 2, Page 2, in the event that there are no shippers for the transportation service under Rate 332, the Company proposes to allocate the entire revenue requirement of Segment A to its distribution customers.

Witnesses: K. Culbert
C. Fernandes
T. Horton
A. Kacicnik
S. Murray

ii) Please see Enbridge's Binding Transportation Open Season materials and indicated Contract Demand (CD) charges, which are attached to the response to BOMA Interrogatory #2 at Exhibit I.A1.EGD (Update).BOMA.2.

Witnesses: K. Culbert
C. Fernandes
T. Horton
A. Kacicnik
S. Murray

REVENUE REQUIREMENT
TCPL 23d(iii) - Parkway to Albion 36"

Line No.	($000's)	2015	2016	2017
	Cost of capital			
1.	Rate base	56,577.9	266,602.9	258,035.1
2.	Required rate of return	6.81%	6.81%	6.81%
3.	Cost of capital	3,853.3	18,157.1	17,573.6
	Cost of service			
5.	Operation and Maintenance	49.0	235.2	235.2
6.	Depreciation and amortization	1,428.2	8,569.4	8,569.5
7.	Municipal and other taxes	170.2	816.9	817.0
8.	Cost of service	1,647.4	9,621.5	9,621.6
	Income taxes on earnings			
12.	Excluding tax shield	(2,389.4)	(4,276.1)	(4,031.4)
13.	Tax shield provided by interest expense	(527.4)	(2,485.2)	(2,405.4)
14.	Income taxes on earnings	(2,916.8)	(6,761.3)	(6,436.8)
	Taxes on (def) / suff.			
15.	Gross (def.) / suff.	(3,515.4)	(28,595.0)	(28,242.7)
16.	Net (def.) / suff.	(2,583.8)	(21,017.3)	(20,758.4)
17.	Taxes on (def.) / suff.	931.6	7,577.7	7,484.3
18.	**Revenue requirement**	3,515.4	28,595.0	28,242.7

Notes:
(1) Revenue Requirement estimate is for the entire Parkway to Albion Pipeline.
(1) Above estimate based in 2013 dollars and on 2013 feasibility parameters.

REVENUE REQUIREMENT
TCPL 23d(iv) - Parkway to Albion 42"

Line No.	($000's)	2015	2016	2017
	Cost of capital			
1.	Rate base	66,369.9	312,664.6	302,499.7
2.	Required rate of return	6.81%	6.81%	6.81%
3.	Cost of capital	4,520.2	21,294.1	20,601.9
	Cost of service			
5.	Operation and Maintenance	55.5	266.6	266.6
6.	Depreciation and amortization	1,694.4	10,166.5	10,166.6
7.	Municipal and other taxes	199.7	958.3	958.3
8.	Cost of service	1,949.6	11,391.5	11,391.5
	Income taxes on earnings			
12.	Excluding tax shield	(2,762.6)	(5,006.8)	(4,720.8)
13.	Tax shield provided by interest expense	(618.7)	(2,914.6)	(2,819.8)
14.	Income taxes on earnings	(3,381.3)	(7,921.4)	(7,540.7)
	Taxes on (def) / suff.			
15.	Gross (def.) / suff.	(4,202.0)	(33,692.9)	(33,269.0)
16.	Net (def.) / suff.	(3,088.5)	(24,764.2)	(24,452.7)
17.	Taxes on (def.) / suff.	1,113.5	8,928.6	8,816.3
18.	**Revenue requirement**	4,202.0	33,692.9	33,269.0

Notes:
(1) Revenue Requirement estimate is for the entire Parkway to Albion Pipeline.
(2) Above estimate based in 2013 dollars and on 2013 feasibility parameters.

REVENUE REQUIREMENT
TCPL 23d(vii) - BramWest to Albion 36"

($000's)

Line No.		2015	2016	2017
	Cost of capital			
1.	Rate base	45,671.9	218,932.3	211,845.4
2.	Required rate of return	6.81%	6.81%	6.81%
3.	Cost of capital	3,110.5	14,910.5	14,427.8
	Cost of service			
5.	Operation and Maintenance	46.1	221.2	221.2
6.	Depreciation and amortization	1,181.4	7,088.2	7,088.3
7.	Municipal and other taxes	139.8	671.0	671.0
8.	Cost of service	1,367.2	7,980.5	7,980.5
	Income taxes on earnings			
12.	Excluding tax shield	(1,948.4)	(3,519.9)	(3,319.3)
13.	Tax shield provided by interest expense	(425.7)	(2,040.8)	(1,974.8)
14.	Income taxes on earnings	(2,374.1)	(5,560.8)	(5,294.0)
	Taxes on (def) / suff.			
15.	Gross (def.) / suff.	(2,862.1)	(23,578.4)	(23,284.7)
16.	Net (def.) / suff.	(2,103.6)	(17,330.1)	(17,114.3)
17.	Taxes on (def.) / suff.	758.5	6,248.3	6,170.5
18.	**Revenue requirement**	2,862.1	23,578.4	23,284.7

Notes:
(1) Revenue Requirement estimate is for the entire BramWest to Albion Pipeline.
(2) Above estimate based in 2013 dollars and on 2013 feasibility parameters.

REVENUE REQUIREMENT
TCPL 23d(viii) - BramWest to Albion 42"

Line No.	($000's)	2015	2016	2017
	Cost of capital			
1.	Rate base	53,731.4	257,626.6	249,200.7
2.	Required rate of return	6.81%	6.81%	6.81%
3.	Cost of capital	3,659.4	17,545.8	16,971.9
	Cost of service			
5.	Operation and Maintenance	46.1	221.2	221.2
6.	Depreciation and amortization	1,404.5	8,427.2	8,427.2
7.	Municipal and other taxes	164.5	789.7	789.7
8.	Cost of service	1,615.1	9,438.1	9,438.2
	Income taxes on earnings			
12.	Excluding tax shield	(2,270.1)	(4,143.8)	(3,907.4)
13.	Tax shield provided by interest expense	(500.9)	(2,401.5)	(2,323.0)
14.	Income taxes on earnings	(2,771.0)	(6,545.4)	(6,230.4)
	Taxes on (def) / suff.			
15.	Gross (def.) / suff.	(3,406.2)	(27,807.5)	(27,455.3)
16.	Net (def.) / suff.	(2,503.6)	(20,438.5)	(20,179.7)
17.	Taxes on (def.) / suff.	902.7	7,369.0	7,275.7
18.	**Revenue requirement**	3,406.2	27,807.5	27,455.3

Notes:
(1) Revenue Requirement estimate is for the entire BramWest to Albion Pipeline.
(2) Above estimate based in 2013 dollars and on 2013 feasibility parameters.

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO TCPL INTERROGATORY #24

INTERROGATORY

Issue A3

Reference(s) (i) Exhibit A, Tab 3, Schedule 1
(ii) Exhibit A, Tab 3, Schedule 6

Preamble
TransCanada would like to better understand the specific market requirements and associated capacity for the EGD distribution system.

Request
(a) Please provide what capacity (TJ/d) is required on Segment A to meet:
(i) Only the current market requirement for EGD distribution purposes
(ii) current and expected growth in market requirement for EGD distribution out to 2025, itemized by categories such as degree day requirements or other specific requirements

(b) Please confirm that the difference between the capacity requirement (TJ/d) for (i) and (ii) in response (a) is the expected market growth for EGD distribution out to 2025. If not confirmed, please explain why not.

(c) Please provide the minimum facilities and design parameters (including temperatures and inlet/outlet pressure) required and associated capital cost that EGD would need for Segment A to serve only its market requirements for distribution purposes and nothing else for the capacity requirements (TJ/d) indicated for each of (i) and (ii) in response (a).

When providing this information, please differentiate the capital costs into separate line items for each of pipe, compression, metering, odorization, and any other capital costs, as well as the grand total.

(d) For the two facilities sets for Segment A provided in response (c), please provide the detailed annual rate base and annual revenue requirement calculations (by individual cost item) for each year of 15 years starting at the November 1, 2015 in service date. The annual revenue requirement calculations should include all expected costs associated with these facilities, including but not limited to depreciation expense, debt return, equity return, income tax, operations and maintenance, pipeline integrity costs, municipal and other taxes. Also please

Witnesses: J. Denomy
C. Fernandes
E. Naczynski

provide all the assumptions used in these calculations, such as depreciation rates for each type of facilities, income tax rate, CCA rate, return on equity %, debt rate, debt to equity ratio, and any escalation or inflation rates used.

RESPONSE

a) Segment A is planned to have 800 TJ/d starting in 2015. This will be used to meet peak day requirements over the 2015 to 2025 period. Growth in GTA demand will be met through other supply paths as the growth occurs.

b) Please see a).

c) The facilities, as proposed, are the minimum facilities required to meet the project objectives. The NPS 42 Segment A pipeline will be designed to meet the prevailing transmission pressure at Parkway/Parkway West, and thus account for the eventual coordinated build out of the Parkway to Maple path, utilizing the current discharge pressure from Parkway/Parkway West. If the Segment A pipeline were to be designed with different parameters, under the hypothetical situation where Enbridge was only going to meet the 800 TJ/d distribution system requirement, there would be many different combinations of inlet pressures and pipe sizes that could be utilized to achieve this flow. For example, a Segment A NPS 42 pipe sizing would meet the distribution only requirement with an inlet pressure of approximately 530 psi. This hypothetical scenario would have no differences in the capital costs as compared to what has been filed in evidence already. Another potential combination would be an NPS 36 with a higher than normal distribution pressure. Capital costs for this scenario have been filed in previous evidence.

d) Please see c).

Witnesses: J. Denomy
C. Fernandes
E. Naczynski

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
TCPL INTERROGATORY #25

INTERROGATORY

Issue A3

Reference(s) (i) Exhibit A, Tab 2, Schedule 4, Pages 5-6
(ii) Exhibit C, Tab 2, Schedule 1, Table 1

Preamble
TransCanada is trying to understand the differences between the various GTA project proposals.

Request
(a) Please list all of the Segment A facility changes and associated capital costs associated with the updated evidence filed on July 22, 2013.

(b) Please provide a table similar to reference (ii) showing the capital costs associated with the GTA project in columns for the following scenarios:
i) Evidence filed December 21, 2012
ii) Update No. 1 as amended February 12, 2013
iii) Update No. 2 as amended Apr 15 , 2013
iv) Update No. 3 as amended May 15, 2013
v) Update No. 4 as amended June 3, 2013
vi) Update No. 5 as amended June 3, 2013
vii) Update No. 6 as amended July 22, 2013

Please include a written description of each scenario. The description should include the major pipeline facilities, metering facilities, odorization facilities, etc. including pipe size for each scenario.

(c) Please provide the total annual revenue requirement for each scenario by year for 15 years starting November 1, 2015.

Witnesses: K. Culbert
T. Horton
S. Murray

RESPONSE

(a) Please see variance analysis provided as an attachment to the response to CCC Interrogatory #30 found at Exhibit I.A3.EGD (Update).CCC 30.

(b) Please see variance analysis provided as an attachment to the response to CCC Interrogatory #30 found at Exhibit I.A3.EGD (Update).CCC.30.

For clarity, the evidence filed December 21, 2012 is in reference to the original scope where Segment A originated at the original Parkway West location and terminated at Albion with a NPS 36 pipeline. This scenario included check metering and odorization at Parkway West for the Segment A pipeline.

Updates No. 1 and 2 had Segment A interconnecting with TransCanada at Bram West and terminating at Albion with a NPS 42 pipeline. This scenario did not have Segment A odourized or metered at Bram West. Custody transfer (CT) metering for Segment A was included at Albion. The change to the project scope was included in Update No. 1 and the corresponding changes to the capital cost and economic feasibility were included in Update No. 2.

Update No. 3 had no impact on capital costs, however the economic feasibility was updated to include a revision to the expected gas supply benefits as a result of the TransCanada's May 1 2013 Compliance Filing and Review and Variance Application.

Updates No. 4 and 5 had no capital cost impact. Update No. 4 provided an update to the economic feasibility in relation to the correction to the customer additions forecast. Update No.5 (June 11, 2013 instead of June 3, 2013 as stated in the interrogatory) provided an update to the Environmental Report.

In response to Interrogatories submitted on June 7, 2013, the capital cost was updated to reflect the change to the Bram West to Albion pipeline size from NPS 42 to NPS 36. This change was discussed in the response to Board Staff Interrogatory #48 at Exhibit I.D5.EGD.STAFF.48. This capital cost and variance analysis is also included in the response to CCC Interrogatory #30 found at Exhibit I.A3.EGD (Update).CCC.30.

Witnesses: K. Culbert
T. Horton
S. Murray

The last amendment, Update 6 has Segment A originating at the new Parkway West location and terminating at Albion with a NPS 42 pipeline. Segment A remains unodorized and custody transfer ("CT") metering is installed at Albion with an additional set of CT meters for a path to continue to Maple.

In all cases Segment B scope remained unchanged.

(c) Please see schedules provided in the attachment. Note, Updates No. 1, No. 3, No. 4 and No. 5 contained no revenue requirement impacts and hence items (ii) and (iv) to (vi) have been omitted. The total revenue requirement is also provided for the update that included NPS 36 Bram West to Albion (submitted through the Interrogatory responses on June 7, 2013, as mentioned in the response to (c) above).

Analysis is shown for 2015-2017. After 2016, all of the forecast capital is included and the first full year of depreciation can be seen in 2017.

Witnesses: K. Culbert
T. Horton
S. Murray

TOTAL REVENUE REQUIREMENT
Evidence filed Dec. 21, 2012
(Note: Includes NPS 36 from original Parkway West location to Albion)

Line No.	($000's)	2015	2016	2017
	Cost of capital			
1.	Rate base	480,286.4	549,673.8	530,228.1
2.	Required rate of return	6.29%	6.29%	6.29%
3.	Cost of capital	30,196.4	34,558.9	33,336.3
	Cost of service			
5.	Operation and Maintenance	-	-	-
6.	Depreciation and amortization	15,912.8	19,445.6	19,445.6
7.	Municipal and other taxes	3,451.9	3,451.9	3,451.9
8.	Cost of service	19,364.6	22,897.5	22,897.5
	Income taxes on earnings			
12.	Excluding tax shield	(6,186.6)	(7,969.8)	(7,546.5)
13.	Tax shield provided by interest expense	(4,453.7)	(5,097.2)	(4,916.8)
14.	Income taxes on earnings	(10,640.4)	(13,067.0)	(12,463.4)
	Taxes on (def) / suff.			
15.	Gross (def.) / suff.	(52,953.3)	(60,393.7)	(59,551.6)
16.	Net (def.) / suff.	(38,920.7)	(44,389.4)	(43,770.4)
17.	Taxes on (def.) / suff.	14,032.6	16,004.3	15,781.2
18.	**Revenue requirement**	$ 52,953.3	$ 60,393.7	$ 59,551.6

TOTAL REVENUE REQUIREMENT
Update No.2 (Apr. 15, 2013)
(Note: Includes NPS 42 from Bram West to Albion)

Line No.	($000's)	2015	2016	2017
	Cost of capital			
1.	Rate base	121,906.9	583,524.9	565,891.1
2.	Required rate of return	6.81%	6.81%	6.81%
3.	Cost of capital	8,302.5	39,741.2	38,540.2
	Cost of service			
5.	Operation and Maintenance	274.5	1,317.7	1,317.7
6.	Depreciation and amortization	2,939.4	17,636.5	17,636.6
7.	Municipal and other taxes	372.1	1,785.9	1,785.9
8.	Cost of service	3,586.0	20,740.0	20,740.1
	Income taxes on earnings			
12.	Excluding tax shield	(5,272.6)	(9,511.5)	(8,979.1)
13.	Tax shield provided by interest expense	(1,136.4)	(5,439.5)	(5,275.1)
14.	Income taxes on earnings	(6,409.0)	(14,951.0)	(14,254.2)
	Taxes on (def) / suff.			
15.	Gross (def.) / suff.	(7,455.1)	(61,945.9)	(61,260.1)
16.	Net (def.) / suff.	(5,479.5)	(45,530.3)	(45,026.2)
17.	Taxes on (def.) / suff.	1,975.6	16,415.7	16,233.9
18.	**Revenue requirement**	$ 7,455.1	$ 61,945.9	$ 61,260.1

TOTAL REVENUE REQUIREMENT
Update No.6 (Jul. 22, 2013)
(Note: Includes NPS 42 from revised Parkway West location to Albion)

Line No.	($000's)	2015	2016	2017
	Cost of capital			
1.	Rate base	135,515.5	639,261.0	619,936.1
2.	Required rate of return	6.81%	6.81%	6.81%
3.	Cost of capital	9,229.3	43,537.1	42,221.0
	Cost of service			
5.	Operation and Maintenance	283.7	1,361.7	1,361.7
6.	Depreciation and amortization	3,221.3	19,328.0	19,328.1
7.	Municipal and other taxes	407.6	1,956.4	1,956.5
8.	Cost of service	3,912.6	22,646.1	22,646.3
	Income taxes on earnings			
12.	Excluding tax shield	(5,776.0)	(10,387.3)	(9,804.5)
13.	Tax shield provided by interest expense	(1,263.2)	(5,959.1)	(5,778.9)
14.	Income taxes on earnings	(7,039.2)	(16,346.3)	(15,583.4)
	Taxes on (def) / suff.			
15.	Gross (def.) / suff.	(8,303.0)	(67,805.4)	(67,052.9)
16.	Net (def.) / suff.	(6,102.7)	(49,836.9)	(49,283.9)
17.	Taxes on (def.) / suff.	2,200.3	17,968.4	17,769.0
18.	**Revenue requirement**	$ 8,303.0	$ 67,805.4	$ 67,052.9

TOTAL REVENUE REQUIREMENT
Interrogatory Responses (June 7, 2013)
(Note: Includes NPS 36 from Bram West to Albion)

($000's)

Line No.		2015	2016	2017
	Cost of capital			
1.	Rate base	113,621.5	543,728.2	527,457.4
2.	Required rate of return	6.81%	6.81%	6.81%
3.	Cost of capital	7,738.2	37,030.8	35,922.7
	Cost of service			
5.	Operation and Maintenance	274.5	1,317.7	1,317.7
6.	Depreciation and amortization	2,712.3	16,273.6	16,273.7
7.	Municipal and other taxes	346.6	1,663.7	1,663.7
8.	Cost of service	3,333.4	19,255.1	19,255.2
	Income taxes on earnings			
12.	Excluding tax shield	(4,941.8)	(8,869.4)	(8,373.8)
13.	Tax shield provided by interest expense	(1,059.2)	(5,068.5)	(4,916.9)
14.	Income taxes on earnings	(6,001.0)	(13,937.9)	(13,290.6)
	Taxes on (def) / suff.			
15.	Gross (def.) / suff.	(6,898.8)	(57,616.3)	(56,989.5)
16.	Net (def.) / suff.	(5,070.6)	(42,348.0)	(41,887.3)
17.	Taxes on (def.) / suff.	1,828.2	15,268.3	15,102.2
18.	**Revenue requirement**	$ 6,898.8	$ 57,616.3	$ 56,989.5

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO TCPL INTERROGATORY #26

INTERROGATORY

Issue A3

Reference(s) (i) Exhibit A, Tab 2, Schedule 1, Page 2

Preamble
EGD states that they will construct a new station, the Parkway West Station, to receive gas delivered on the Union Gas' Dawn to Parkway transmission system and that this station will be on land leased from Union Gas.

Request
(a) How much land owned or leased by Union Gas is required for this Station?

(b) What is the cost of the leased land?

(c) Is this cost included in the GTA Project? If so, please explain and provide references.

RESPONSE

(a) EGD has identified the size of the plot plan needed to be leased for their facilities at Union Gas' Parkway West site as approximately 11,000 square metres. Final size required will be confirmed once detail engineering is completed.

(b) Enbridge has had initial discussions with Union Gas and there is agreement from both parties that the land required by Enbridge for their Parkway West Station will be leased from Union Gas. Further discussions and negotiations on lease costs are underway and will continue once Enbridge completes detailed engineering of the facilities to confirm final land requirements.

(c) There is an internally estimated annual lease cost for leasing the land required by EGD for their facilities at Parkway West that was based on past experience and similar lease arrangement EGD currently has in place. The cost has been included in the feasibility.

Witness: B. Madrid

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO TCPL INTERROGATORY #27

INTERROGATORY

Issue A3

Reference(s) (i) Exhibit A, Tab 3, Schedule 1, paragraphs 9 and 10.

Preamble

EGD discusses its plans to hold a New Capacity Open Season to allocate capacity for the transportation element of Segment A and discusses the rate to be charged for this service.

Request

(a) What is the minimum term requested in the open season?

(b) Will successful bidders be obligated to renew their contracts beyond the initial term of the contract? If so, what are the terms and conditions and rate to be charged for this service?

c) Are there any obligations regarding the remaining NBV of the Segment A facilities at the end of the term of the contract if it is not renewed?

d) Please compare this commitment to pay for costs on Segment A with the commitment made by TransCanada in the MOU.

RESPONSE

a) Please see the response to Environmental Defence Interrogatory #48 at Exhibit I.A3.EGD (Update).ED.48.

b) No, shippers on the Albion Pipeline will not be obligated to renew their contracts beyond the initial term of the contract.

Witness: M. Giridhar

c) No, at the end of the initial contract term there are no further obligations to shippers related to the NBV who have not renewed their capacity.

d) In the MOU, TransCanada committed to pay for the residual net book value of its capacity share of the Segment A pipeline, in the event it did not renew its transportation contract. This arrangement mimicked joint ownership and was consistent with the granting of exclusive use of the transmission capacity to TransCanada during the initial contract term and the associated obligation created for TransCanada to provide transmission service from Parkway to shippers requesting service on a reasonable and non-discriminatory basis and in a manner that would be compliant with the transportation access procedures of the NEB.

Witness: M. Giridhar

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
TCPL INTERROGATORY #28

INTERROGATORY

Issue A3

Reference(s) (i) Exhibit A, Tab 3, Schedule 9, paragraph 6.

Preamble
EGD discusses the cost of a larger diameter pipeline for Segment A. “The approximately $55 million cost of a larger diameter pipeline is less than the potential monetary benefits for distribution ratepayers of approximately $133 million in the first year alone.”

Request
(a) Please provide the details including pipe, compression, metering, odorization, land, any other capital costs, and operating costs supporting the $55 M additional cost.

(b) Is this $55 M additional cost incremental to the additional cost of changing the origin of Segment A from Bram West to Parkway? If yes, please provide the details of these costs including pipe, compression, metering, odorization, land, any other capital costs, and operating costs?

RESPONSE

a) The “approximately $55 million” additional cost was a total cost factored estimation. This was calculated based on the previously submitted difference in total project cost estimates for the NPS 42 and NPS 36 Segment A pipeline with Bram West initiation point. The difference in the estimate for the different pipe sizing was scaled based on the increased length. No detailed cost estimate was performed, and no detailed cost breakdowns are available.

b) The $55 million is an approximation of the cost difference of the entire GTA project with a NPS 42 Segment A pipeline as compared to the entire GTA project with a

Witnesses: C. Fernandes
T. Horton

NPS 36 Segment A pipeline, in both cases with the origination point of Segment A at Parkway West.

Witnesses: C. Fernandes
T. Horton

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
TCPL INTERROGATORY #29

INTERROGATORY

Issue A3

Reference(s) (i) Exhibit A, Tab 3, Schedule 9, Paragraph 8

Preamble
EGD discusses the open season for Segment A and states:" …60% of the revenue requirement for the Segment A pipeline will be allocated to the transportation service and 40% will be allocated to distribution. In the event there are no shippers for the transport service, distribution ratepayers will be allocated the entire revenue requirement."

Request
(a) Please confirm that the total annual revenue requirement for Segment A is estimated to be approximately $33 M. If not please explain & provide the correct amount.

(b) Please confirm that EGD has allocated 60% of the total cost of Segment A to transportation service and that the annual costs allocated would be approximately $20 M. If not confirmed please explain and provide the correct amounts.

(c) Please provide the methodology for allocating Segment A costs to transportation service shippers if less than 100% of the available capacity is subscribed.

(d) In addition to the 40% of Segment A costs being allocated to distribution customers, please provide the annual $ amounts that will be allocated to distribution customers if the Segment A capacity offered in the open season is totally unsubscribed, 10% subscribed, 25% subscribed, 50% subscribed, 75% subscribed and 90% subscribed.

Witnesses: K. Culbert
A. Kacicnik
S. Murray

RESPONSE

a) Confirmed.

b) Confirmed.

c) Please see the response to APPrO Interrogatory #15 found at Exhibit 1.A.3.EGD (Update).Appro.15.

d) If the transportation portion of Segment A is totally unsubscribed then, based on the 2016 revenue requirement, distribution ratepayers would be allocated approximately an additional $20 M in revenue requirement. Please see the response to APPrO Interrogatory #15 found at Exhibit 1.A.3.EGD (Update).Appro.15 for the manner in which Enbridge proposes to recover the revenue requirement if the pipeline were partially undersubscribed.

Witnesses: K. Culbert
A. Kacicnik
S. Murray

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
TCPL INTERROGATORY #30

INTERROGATORY

Issue A3

Reference(s) (i) Exhibit A, Tab 3, Schedule 9, Paragraph 9

Preamble
EGD discusses the open season for Segment A and Financial Backstopping Agreements (“FBAs”) and that shippers are expected to bear some of the risk on upfront costs associated with Segment A.

Request
(a) Please explain what EGD means by the “risk on upfront costs”

(b) Please define the term “some” of the risk. Please quantify the upfront costs and the amount of these costs shippers are expected to bear.

(c) Would costs associated with FBAs only materialize if the party fails to contract on a firm basis.

(d) Do the FBAs contain any conditions precedent? If so, please list them.

RESPONSE

a) The relevant contractual obligations in relation to the shipper’s risk on upfront costs are set forth in the terms of the Financial Backstopping Agreement (“FBA”).

b) The shipper’s exposure to certain costs, which are defined as “Pre-service Costs” in the FBA, is set forth in Section 3 of the agreement. The Pre-service Costs cannot be defined by Enbridge until the conclusion of the Open Season process.

Witness: M. Giridhar

c) It is assumed that this question is asking when a shipper's obligation to reimburse Enbridge for "Pre-Service Costs" (as such term is defined in the FBA) would materialize. Section 3 of the FBA sets forth when such shipper's obligation to reimburse Enbridge would materialize.

d) No, the FBA does not contain any conditions precedent.

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
TCPL INTERROGATORY #31

INTERROGATORY

Issue A3

Reference(s) (i) Exhibit A, Tab 3, Schedule 9, Paragraph 9

Preamble
Do the proposed facilities meet the Board's economic tests as outlined in the Filing Guidelines on the Economic Tests for Transmission Pipeline Applications, dated February 21, 2013 and E.B.O. 188 as applicable?

Request
(a) Does EGD acknowledge that since Segment A provides open access transportation services to ex-franchise customers, the Segment A expansion is subject to the Board's Guidelines mentioned above? Please explain in full.

(b) Please provide the evidence references to EGD's assessment of the impact of the GTA project on existing transportation infrastructure in Ontario and the impacts on Ontario customers in terms of costs, rates, reliability, and access to supplies.

RESPONSE

a) Enbridge acknowledges that the Albion pipeline provides for non-discriminatory open market access to all shippers including ex-franchise customers. Enbridge acknowledges that the proposed facilities fall under the Board's EBO 134 and EBO 188 guidelines. Please refer to Exhibit E, Tab 1, Schedule 1, paragraphs 4 to 6.

b) Please see Exhibit E, Tab 1, Schedule 1, paragraphs 4 to 6, 17 and 18.

Witness: C. Fernandes

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
TCPL INTERROGATORY #32

INTERROGATORY

Issue A3

Reference(s) (i) Exhibit A, Tab 2, Schedule 1, Page 9 of 11

Preamble
In its evidence, EGD requests the Board to issue an Order(s) granting leave to construct the Segment A and Segment B facilities

Request
(a) Please confirm that EGD is seeking full cost recovery of the facilities applied for in this application

(b) In the absence of full cost recovery for any portion of the GTA Project, will EGD proceed with the installation of the facilities it has requested approval for?

RESPONSE

a) The application requests leave to construct of the proposed facilities and the approval of the rate 332 methodology. Enbridge is seeking full cost recovery of the facilities; consideration of the rate impact and cost allocations for existing rates will take place in Enbridge's EB-2012-0459 rate proceeding.

b) Enbridge plans to proceed with the proposed facilities based on the Board granting leave to construct of the proposed facilities. Enbridge expects full cost recovery of prudent expenditure of Board approved leave-to-construct facilities.

Witnesses: C. Fernandes
M. Giridhar

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO TCPL INTERROGATORY #33

INTERROGATORY

Issue A3

Reference(s) (i) Exhibit A, Tab 2, Schedule 1, Page 8 of 11 Paragraph 27

Preamble

EGD states the "updated estimated cost of the GTA project is $686.5M

Request

(a) Please provide a breakdown of this cost by each proposed segment. i.e Segment A, Segment B, tie in costs, metering costs, odorization, and other costs. (please specify)

RESPONSE

Enbridge has provided a detailed breakdown as confidential information for which TCPL has signed the undertaking and declaration. Please see the confidential version of Exhibit D, Tab 1, Schedule 2.

Please also see attachment to CCC Interrogatory #30 found at Exhibit I.A3.EGD (Update).CCC 30 for a detailed cost variance. The confidential version of the attachment will be provided to parties who have signed the Declaration and Undertaking.

Witness: T. Horton

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
TCPL INTERROGATORY #34

INTERROGATORY

Issue A3

Reference(s) (i) Exhibit A, Tab 3, Schedule 9, Page 2 of 16

Preamble
The shared usage of the Segment A pipeline for distribution and transmission, and also the path through Albion, is a preferred path for regional infrastructure development. This has been supported by both Union and TransCanada as compared to other alternatives for elimination of the Parkway to Maple constraint.

Request
(a) Please confirm that TransCanada's support for the shared usage and build out of the path between Bram West and Albion involved TransCanada as either an owner or proponent in the infrastructure build and provided TransCanada with transportation contracts between Parkway and Bram West.

RESPONSE

a) Enbridge understood that TransCanada's support was based on the principles embodied in the MOU. Section 2.1 of the MOU states the purpose of the MOU. The first listed purpose in this section states, "….the efficient development of natural gas infrastructure in the GTA and on TransCanada's Parkway to Maple path;"

   Enbridge believes that the shared usage of the Segment A was deemed by TransCanada to be the most efficient alternative to build out the Parkway to Maple path. TransCanada's other alternative as shown in I.A1.EGD.CME.6 Attachment 6 included approximately 40 km of NPS 42 pipeline. Additional pipeline facilities would also be required to meet Enbridge's distribution needs at Albion. The GTA project's shared usage of Segment A pipeline offers a more efficient build out of the Parkway to Maple path.

Witness: M. Giridhar

With the arrangement as described in the 2013-07-22 update, the principle of the shared usage of the Segment A pipeline for distribution and transmission, and the efficiency of the Parkway- to-Maple build through Albion have not changed. Enbridge has consulted with TransCanada, and continues to consult with TransCanada, in order to provide non-discriminatory open market access to short haul service that will connect to and travel on TransCanada's mainline system and provide TransCanada with transportation contracts.

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
TCPL INTERROGATORY #35

INTERROGATORY

Issue A3

Reference(s) (i) Exhibit A, Tab 2, Schedule 1, Page 3, Paragraph 9
(ii) Exhibit A, Tab 3, Schedule 8, Page 5, Paragraph 12

Preamble
EGD states it will hold an open season for Segment A, which has been sized assuming that it will be used to serve needs beyond those of EGD.

Request
(a) Please provide a copy of the open season for service from Parkway to Albion, and the supporting documents including the associated precedent agreements which will be used.

(b) Please itemize and describe the conditions precedent which are in the Precedent Agreement.

(c) Please provide any presentations, meeting notes, e-mails or marketing materials to any potential bidders or to industry, and any internal presentations with respect to Segment A.

RESPONSE

a) Please see the response to BOMA Interrogatory #2 at Exhibit I.A1.EGD (Update).BOMA.2.

b) Please refer to Section 3 of the Precedent Agreement for the Albion Pipeline Open Season.

c) Please see attached.

Witness: M. Giridhar

NEWS RELEASE

Enbridge Gas Distribution Announces Binding Transportation Open Season for Parkway to Albion Pipeline Project

TORONTO, ON – July 24, 2013 – Enbridge Gas Distribution Inc. today announced that it is conducting a binding transportation open season for the Parkway to Albion Pipeline Project, offering firm transportation service on a proposed pipeline from the new Parkway West gate station to a new interconnect at the Albion Road gate station.

The Parkway to Albion Pipeline Project will provide firm transportation capacity of approximately 2,000 TJ/d from Parkway to Albion of which 800 TJ/d will be reserved for Enbridge's distribution customers, and up to 1,200 TJ/d for market access. Service on this segment would commence as early as November 1, 2015.

The project is constituted as part of Enbridge's GTA Project (EB-2012-0451) therein known as Segment A. The GTA project has been advanced in order to meet the demands of customer growth in the Greater Toronto Area and to continue the safe and reliable distribution of natural gas to current and future customers. The open season provides access to diverse natural gas supplies from Niagara and Dawn.

Information packages and bid forms are available online at EnbridgeGas.com/openseason. Inquiries regarding this binding transportation open season can be directed to Ian Macpherson at 416-495-6535 or via email at ian.macpherson@enbridge.com

In order to be considered, all signed bid forms must be received by noon eastern time on September 6, 2013. Bid forms should be emailed or faxed to Ian Macpherson at 416-498-3816 or ian.macpherson@enbridge.com.

About Enbridge Gas Distribution

Enbridge Gas Distribution Inc. has a more than 160-year history and is Canada's largest natural gas distribution company. Enbridge Gas Distribution delivers safe, reliable natural gas in more than 100 communities across Ontario and is a leader in promoting energy efficiency programs. It is owned by Enbridge Inc., a Canadian-based leader in energy transportation and distribution and one of the 2013 Global 100 Most Sustainable Corporations. Enbridge Inc. has been selected as one of Canada's Greenest Employers for 2013 and is one of Canada's Top 100 Employers. Enbridge Gas Distribution and its affiliates distribute natural gas to two million customers in Ontario, Quebec, New York State and New Brunswick. For more information, visit www.enbridgegas.com.

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Media Contact:
Paul Green
Tel: 416-495-5927
Email: Paul.Green@enbridge.com

ENBRIDGE GAS DISTRIBUTION INC. RESPONSE TO
TCPL INTERROGATORY #36

INTERROGATORY

Issue A3

Reference(s) (i) EGD EB-2013-0074 Application

Preamble
TransCanada wishes to be better able to follow changes made to the initial EGD application.

Request
(a) Please provide a blackline version of the EB-2012-0451 Application which tracks all changes since the original application was filed.

RESPONSE

Clarification was received directly from TransCanada on August 7, 2013 on the specific blackline request. The request is to provide a blackline version from the original Application and Evidence (December 21, 2012) to the most current Application and Evidence (July 22, 2013, or the most recent submission date) for select exhibits. Please see the attachment for the requested blackline version. A summary of the exhibits included and not included in the blackline version is provided on the following page.

Witness: C. Fernandes

A – PURPOSE, NEED, & TIMING				
Exhibit	Tab	Schedule	Contents	Blackline Version
A	1	1	Exhibit List	Not requested
	2	1	Application	Included[1]
		2	OPCC Distribution List	Not requested
		3	List of Interested Parties	Not requested
		4	Summary of Changes	Not requested
	3	1	Purpose, Need, and Timing	Included
		2	History of Natural Gas Supply in the GTA	Included[2]
		3	Operation and Limitations of Existing Facilities	Included[3]
		4	Market Growth	Included
		5	Natural Gas Demand, Supply, and Expected Gas Supply Benefits	Included
		6	Proposed Facilities, Operation, and System Benefits	Included
		7	Alternatives	Included[4]
		8	Timing	Included
		9	July 22, 2013 Update to Exhibit A, Tab 3	Not Included[5]

[1] Attachment Figure 2 is not included as there are no changes from the original Application.
[2] Attachment to this exhibit is not included as there are no changes from the original Application.
[3] Attachment to this exhibit is not included as there are no changes from the original Application.
[4] Attachment to this exhibit is not included as there are no changes from the original Application.
[5] This is a new exhibit in relation to the original Application and Evidence.

Witness: C. Fernandes

B – ROUTING AND ENVIRONMENTAL				
Exhibit	Tab	Schedule	Contents	
B	1	1	Preferred Route Description	Not requested
		2	Alternative Route Description	Not requested
B	2	1	Environmental Report and Archaeological Assessment	Not requested
		2	Environmental Implementation Plan	Not requested
C – FACILITIES AND PROJECT COSTS				
C	1	1	Design Specifications	Included
		2	Hydrostatic Test Procedure	Included
	2	1	Estimated Project Costs	Included
		2	Proposed Construction Schedule	Included
		3	Project Management Framework	Not Included[6]
D – LAND ISSUES				
D	1	1	Land Requirements	Not requested
		2	Negotiations to Date	Not requested
		3	Permits Required	Not requested
		4	Affidavit	Not requested

[6] Exhibit C, Tab 2, Schedule 3 is not included as there are no changes from the original Application and Evidence.

E – ECONOMIC FEASIBILITY				
Exhibit	Tab	Schedule	Contents	
E	1	1	Project Benefits and Economics	Included[7]
		2	Transportation Rate Methodology	Not Included[8]
F – OTHER MATTERS				
F	1	1	Aboriginal Consultations	Not Requested

[7] Attachment 1 is not included since the combination of changes (i.e. capital cost, expected gas supply benefits, correction to the customer additions forecast, etc.) impacts the entire DCF schedule.
[8] This is a new exhibit in relation to the original Application and Evidence.

Witness: C. Fernandes

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 Enbridge Gas Distribution Inc. under section 90 and 91 of the *Ontario Energy Board Act, 1998,* S.O. 1998, c. 15 (Schedule B) for an order or orders granting leave to construct a natural gas pipeline and ancillary facilities in the Town of Milton, City of Mississauga, City of Markham, Town of Richmond Hill, City of Brampton, City of ~~Mississauga, City of~~ Toronto, City of ~~Vaughn~~Vaughan and the Region of Halton, the Region of Peel and the Region of York;

AND IN THE MATTER OF an application by Enbridge Gas Distribution Inc. under section 36 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 (Schedule B) for an order or orders approving the methodology to establish a rate for transportation services;

LEAVE TO CONSTRUCT APPLICATION:

GREATER TORONTO AREA PROJECT

1. The Applicant, Enbridge Gas Distribution Inc. ("**Enbridge**~~"),~~") is an Ontario corporation with its head office in the City of Toronto. It carries on the business of selling, distributing, transmitting and storing natural gas within Ontario.

2. Enbridge hereby applies to the Ontario Energy Board (the "**Board**") for leave to construct the Greater Toronto Area Pipeline Project (the "**GTA Project**") as described herein. The purpose of the GTA Project is to: (i) support future customer growth for the period 2015 to 2025; (ii) eliminate distribution system constraints, (iii) diversify gas supply entry points into the Enbridge distribution system; (iv) reduce operational risks; and (v) provide improved reliability, risk mitigation and cost savings for upstream gas supply.

~~3. Enbridge is continuing to engage Union Gas Ltd. ("Union") and TransCanada Pipelines Limited ("TransCanada") to optimize the GTA Project and the benefits to Enbridge's customers. Details of these discussions are provided at Exhibit A, Tab 3, Schedule 1, Page 10.~~

3. This Application is amended to reflect the cumulative changes to the GTA Project that have occurred since the filing on December 21, 2012 through Update No. 6 dated July 22, 2013.

4. The GTA Project consists of two segments, Segment A and Segment B, each of which are described below.

Segment A

5. Segment A is intended to connect to the Union Gas Limited system at the proposed Parkway West Gate Station and provide delivery of gas to Enbridge's Albion Road Gate Station. Segment A is located in the Region of Halton, Region of Peel, Town of Milton, City of Mississauga, City of Brampton and ~~City of Mississauga and~~ the City of Toronto. A map of Segment A may be found in Attachment Figure 1.

Segment A – Parkway West to Albion Road

6. Enbridge ~~proposes to~~will construct a new station, the Parkway West Gate Station~~, west of Highway 407 and near Derry Road in the Town of Milton~~ to ~~connect to~~ receive gas delivered on the Union ~~Gas Ltd.'s proposed~~Gas' Dawn to Parkway ~~West facility. The Enbridge~~transmission system. Enbridge's Parkway West Gate Station will be ~~comprised of~~located adjacent to the proposed Union Gas Parkway West Station on land leased from Union Gas. Enbridge will have measurement, regulation, valving, odourant ~~and~~, telemetering, and in-line inspection equipment~~.~~ at this site.

~~7. Segment A Preferred Route~~Enbridge will construct a Nominal Pipe Size ("**NPS**") 42 extra high pressure ("**XHP**") pipeline from its proposed Parkway West Gate Station to the Albion Road Gate Station. The proposed route is approximately ~~25.7~~27.4 kilometres ("**km**") long and begins at the proposed ~~at the to be constructed~~ Parkway West Gate Station~~.~~

~~8.~~7. located south of Derry Road and west of Highway 407 in the Town of Milton. The ~~Segment A Pipeline extends northeast from the proposed Parkway West Gate Station to the east~~route of the Segment A pipeline is northerly for approximately 2.4 km as it exits the Parkway West Gate Station on the west side of Highway 407~~,~~ and ~~proceeds~~then continues northeast paralleling ~~the~~an existing Enbridge ~~NPS 36 pipeline~~ easement for approximately 1~~,000 metres. At~~ km on the north side of a generally west-east trending hydro transmission corridor, the ~~Pipeline~~pipeline turns eastward and continues within the Parkway Belt West Plan ~~Area for approximately 24 km. The Segment A pipeline travels within the Parkway Belt West Plan~~ corridor, and predominantly within a designated Utility Corridor, or road right-of-ways, for the remaining approximately 24 km length of the route.

8. ~~The Segment A Pipeline~~This pipeline will terminate at the existing Enbridge Albion Road Station near Highway 427, Albion Road and Indian Line. As part of the GTA Project, Enbridge's Albion Road Station will be expanded to a gate station and will accommodate the new connection ~~to the NPS 36 XHP~~and odourization, metering, regulation and other ancillary equipment.

9. Segment A pipeline will serve both transportation and local distribution needs. Enbridge will retain 800,000 GJ/day for distribution purposes and 1,200,000 GJ/day for transportation purposes. Enbridge will be commencing a New Capacity Open Season in July 2013 to allocate capacity for the transportation element of Segment A.

~~9.~~10. The shared use of Segment A ~~Pipeline.~~will eliminate the need for duplicative pipelines/facilities resulting in less environmental and community impacts. Enbridge does not currently have a methodology or a rate applicable to the transportation service to be provided by Segment A to shippers. Enbridge is seeking approval of the methodology that will be applied to develop a rate ("**Rate 332**") for the transportation service in order to provide shippers with a means to determine their future payment obligations and pursue regulatory approvals. Enbridge will be seeking approval of the new rate, Rate 332, in rate proceeding, EB-2012-0459, when the rate impact of the GTA Project will be considered.

Segment A – Parkway West to Parkway North & Parkway By-Pass

~~10.~~11. In addition to ~~supplying the proposed NPS 36 Pipeline~~the Parkway West to Albion pipeline described above, the proposed Enbridge Parkway West Gate Station will also connect ~~to~~into the existing Enbridge NPS 36 Pipeline (the "**Parkway North**" pipeline) which is located on the west side of Highway 407. This connection will require the installation of approximately ~~180~~315 metres ("**m**") of NPS 36 pipeline to complete the tie-in.

~~11.~~12. Enbridge also proposes to upgrade the existing valve manifold at the existing Parkway By-Pass (located on the west of Highway 407 south of Derry Road and directly west of the Parkway Gate Station) to include pressure regulation between the existing Enbridge NPS 36 ~~XHP~~ "Parkway North" pipeline and the existing Enbridge NPS 36 XHP "Mississauga Southern Link" ~~(~~Pipeline (the "**MSL**~~)~~" pipeline) that currently operate at different pressures.

Segment B

~~12.~~13. Segment B is proposed to be NPS 36 XHP pipeline and the modification and construction of station facilities. A map of Segment B may be found in Attachment Figure 2. The GTA Project - Segment B will be constructed within the Region of York, the City of Vaughan, the City of Markham, City of Toronto and the Town of Richmond Hill.

~~13.~~14. The Segment B pipeline commences at Enbridge's Keele/CNR Station which will be modified to connect to the proposed NPS 36 XHP pipeline.

~~14.~~15. The Segment B Preferred Route is approximately 23 km long and begins at Enbridge's Keele/CNR Station located on Keele Street, approximately 400 ~~metres~~m north of Steeles Avenue in the City of Vaughan.

~~15.~~16. The Segment B Pipeline exits the Keele/CNR Station and travels northeast for approximately 15.4 km, within the Parkway Belt West Plan Area and primarily within the Utility Corridor designation area, to the north-south trending hydro transmission corridor between Pharmacy Avenue and Warden Avenue, in the City of Markham.

~~16.~~17. The Segment B Pipeline turns south to continue along the hydro transmission corridor to McNicoll Avenue, where the hydro transmission corridor ends and continues within the Enbridge owned north-south trending Buttonville utility corridor.

~~17.~~18. The Segment B Pipeline continues south within the utility corridor and terminates just north of Sheppard Avenue, connecting to an existing Enbridge NPS 36 pipeline. The Pipeline travels within Utility Corridors (including the Parkway Belt, Buttonville Corridor) for the majority of pipeline length.

~~18.~~19. Enbridge proposes to construct the Buttonville Regulation Facility ("**Buttonville Station**"), south of Highway 407 and east of Rodick Road in the City of Markham, to tie the new NPS 36 XHP east-west and north-south portions into the existing NPS 30 XHP Pipeline (the "**Don Valley**" pipeline) in the area of the intersection of the two pipelines.

~~19.~~20. Enbridge also proposes to expand the existing "Jonesville-Eglinton Regulation Facility" ("**Jonesville Station**") located within the existing utility corridor north of Eglinton Avenue East and Jonesville Crescent in the City of Toronto. The expansion will provide additional support for the existing NPS 36 XHP pipeline feed into the existing NPS 30

XHP ~~"~~Don Valley~~"~~ pipeline running south from the Jonesville Station to Station B.

~~20.~~21. The route and location for the GTA Project was selected by Dillon Consulting Inc. ("**Dillon**"), an independent environmental consultant, through the process outlined in the Ontario Energy Board's *"Environmental Guidelines for the Location, Construction, and Operation of Hydrocarbon Pipelines in Ontario" (Sixth Edition, 2011).* Input from the public, area stakeholders, ~~Metis~~Métis and First Nations was sought during the route selection process and was incorporated into the final alignment decision. Enbridge will continue to update the ~~Metis~~Métis and First Nations regarding the results of the archeological studies.

~~21.~~22. The route selection and the environmental and socio-economic impact assessment of the proposed facilities are provided in the "*GTA Project: Environmental Report*" (the "**Environmental Report**") found at Exhibit B, Tab 2, Schedule 1, ~~Attachment~~Attachments 1, 4, and 5. The proposed measures outlined in the Environmental Report will be used to mitigate any potential environmental impacts.

~~22.~~23. In addition to the consultation completed as part of the Environmental Report, Enbridge has consulted, and continues to consult, with interested stakeholders. An amendment has been filed as part of Update No. 6 to include the environmental and socio-economic impact assessment of the reinstatement of the originally proposed route as a NPS 42 pipeline and the additional 1.5km of NPS 42 pipeline and facilities from Enbridge's newly proposed Parkway West Gate Station northerly which was not included in the initial Environmental Report. The amendment can be found at Exhibit B, Tab 2, Schedule 2, Attachment 6.

~~23.~~24. Enbridge has included draft agreements at Exhibit D, Tab 1, Schedule 2 that will be offered to affected landowners where the need for an easement arises.

~~24.~~25. There are five (5) individual landowners that will be impacted by the proposed construction. ~~As these individuals are not yet a party to the proceeding,~~ Enbridge has redacted their identities from the matters filed in the public record. Enbridge has filed two copies of the unredacted information regarding the five landowners confidentially with the Board in a separate sealed envelope.

~~25.~~26. Enbridge has filed certain financial and economic information in confidence, pursuant to the Board's *Practice Direction on Confidential Filings* and the *Rules of Practice and Procedure*. Two copies of the unredacted information have been filed in a separate sealed envelope.

~~The estimated cost of the GTA Project is approximately $603 million.~~

~~26.~~27. The updated estimated cost of the GTA Project is $686.5 million. The amended project costs, schedule, and economic feasibility calculations have been provided in the evidence submitted as part of Update No. 6. This evidence has been updated based on the shared usage with shippers, the change in initiation location to Parkway West. The rate methodology and corresponding revenue requirement for services provided to shippers can be found at Exhibit E, Tab 1, Schedule 2. The vast majority of the estimated costs have not yet been committed to or incurred. Access to certain information in the economic ~~modelling~~modeling has also been filed confidentially.

~~27.~~28. Enbridge hereby requests the Board maintain this information in confidence to preserve the integrity of, and ensure customer confidence in, the procurement process. ~~Further details regarding the request for confidentiality are provided with the cover letter to the sealed envelopes containing the unredacted information.~~

~~28.~~29. Enbridge does not object to the confidential information being made available to intervenors in this proceeding subject to such intervenor providing a declaration and undertaking to maintain the confidentiality of the information and to only use such information for this proceeding. Unredacted information will be provided to the Board and those who have signed the declaration and undertaking. Enbridge does not object to the confidential information regarding the project economics becoming public following the completion of its procurement process.

~~29.~~30. The proposed in-service date for ~~Segment A of~~ the ~~project is April 2015 and for Segment B of the~~GTA Project is ~~December 2014~~ prior to November 2015 in order to be available for the winter of 2015. In order to meet the in-service date, construction is scheduled to commence no later than ~~August~~December 2014. Exhibit C, Tab 2, Schedule 2 indicates the proposed construction schedule.

~~30.~~31. The permitting process will require several weeks to, in some instances, more than 1 year. Procurement lead times may also require more than 1 year. Therefore, Enbridge requests that the Board establish a schedule for this Application such that a Decision and Order can be issued by ~~August 1~~December 15, 2013.

~~31.~~32. ~~A~~An updated list of interested parties ~~and~~is provided at Exhibit A, Tab 2, Schedule 3 and the list of permitting authorities is provided at Exhibit ~~A, Tab 2, Schedule 3 and Exhibit~~ D, Tab 1, Schedule 3~~ respectively.~~. The list of interested parties and the list of permitting authorities have been updated with all changes up to and including Update No.6.

~~32.~~33. Enbridge requests this Application be conducted in English.

~~33.~~34. Enbridge ~~request~~requests the Board issue:

~~(i)~~i. such directions and orders as the Board deems appropriate for the notice and proper review, consideration and processing of this Application;

~~(ii)~~ii. such orders as are necessary or advisable for the proper protection, handling and access to the confidential information described herein;

~~(iii)~~iii. pursuant to section 90 and 91 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c-15 (Schedule B), an Order(s) granting leave to construct the GTA Project - Segment A, including Parkway West Gate Station to Albion Road Station, as a NPS 42 pipeline, and other facilities as described herein; ~~and~~

iv. pursuant to section 90 and 91 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c-15 (Schedule B), an Order(s) granting leave to construct the GTA Project - Segment B as described herein;

~~(iv)~~v. pursuant to section 97 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c-15, Schedule B, an Order approving the form of easement agreements found at Exhibit D, Tab 1, Schedule 2, Attachment herein~~.~~;

vi. in order to determine the conditions under which shippers will be provided service, pursuant to section 36 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c-15, Schedule B an Order granting approval for a methodology to determine the rate, Rate 332, in respect of the transportation service provided to shippers.

~~34.~~35. Enbridge requests that copies of all documents filed with the Board in connection with this proceeding be served on it and on its counsel, as follows:

~~(a)~~ The Applicant: Regulatory Affairs

	Enbridge Gas Distribution Inc.
Address for personal service:	500 Consumers Road Toronto, ON M2J 1P8
Mailing Address:	P. O. Box 650 Scarborough, ON M1K 5E3
Telephone:	(416) 495-5499
Fax:	(416) 495-6072
E-Mail:	~~EGDRegulatoryProceedings@enbridge.com~~EGDRegulatoryProceedings@enbridge.com

~~(b)~~ The Applicant's counsel:	Scott Stoll & Fred Cass Aird & Berlis LLP
Address for personal service and mailing address:	Suite 1800, Box 754 Brookfield Place, 181 Bay Street Toronto, Ontario M5J 2T9
Telephone:	(416) 865-4703 (Scott Stoll) (416) 865-7742 (Fred Cass)
Fax:	(416) 863-1515
E-Mail:	~~sstoll@airdberlis.com~~sstoll@airdberlis.com fcass@airdberlis.com

DATED ~~December 21, 2012~~July 22, 2013 at Toronto, Ontario.

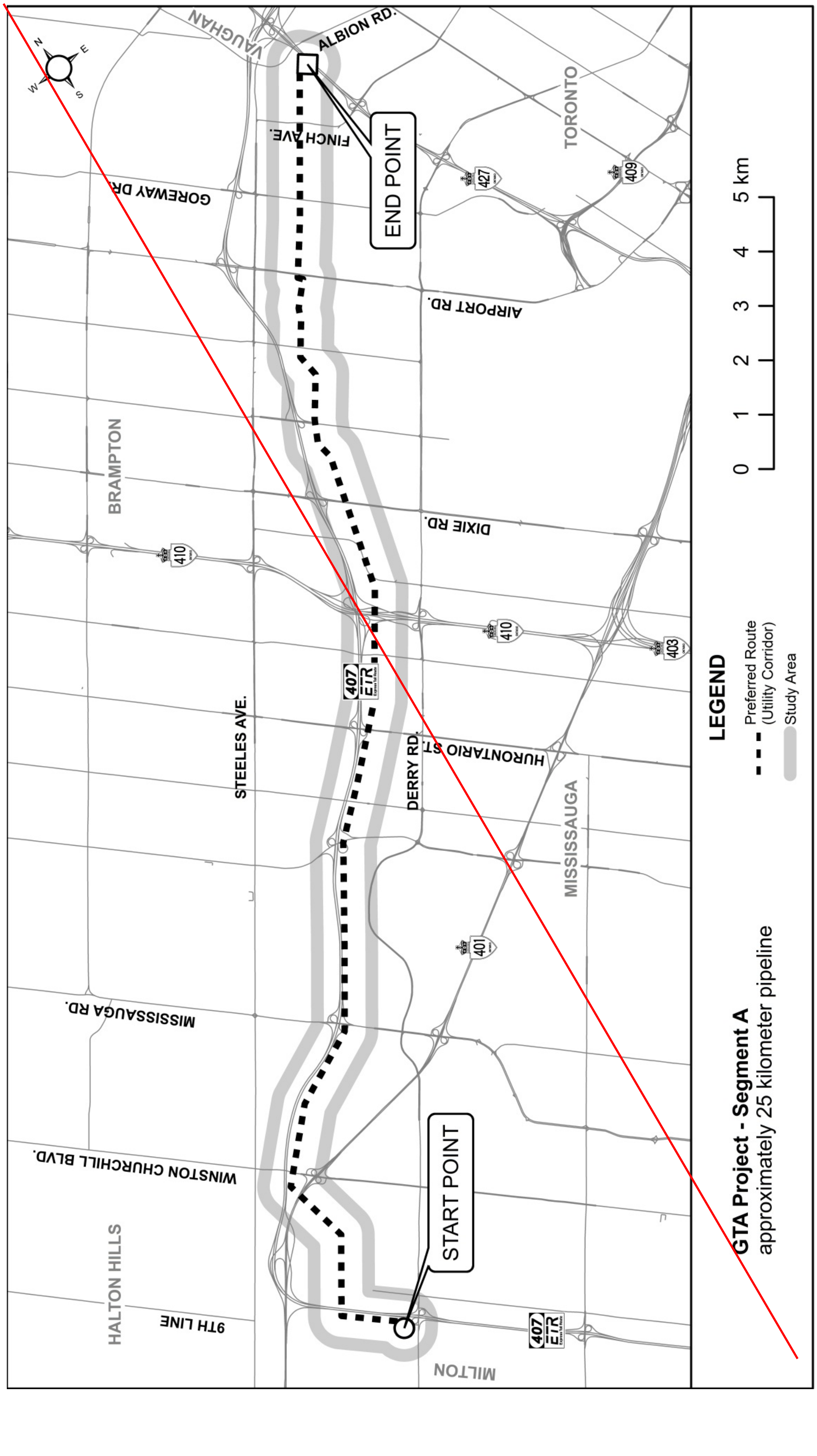
ENBRIDGE GAS DISTRIBUTION INC.
By its counsel

AIRD & BERLIS LLP

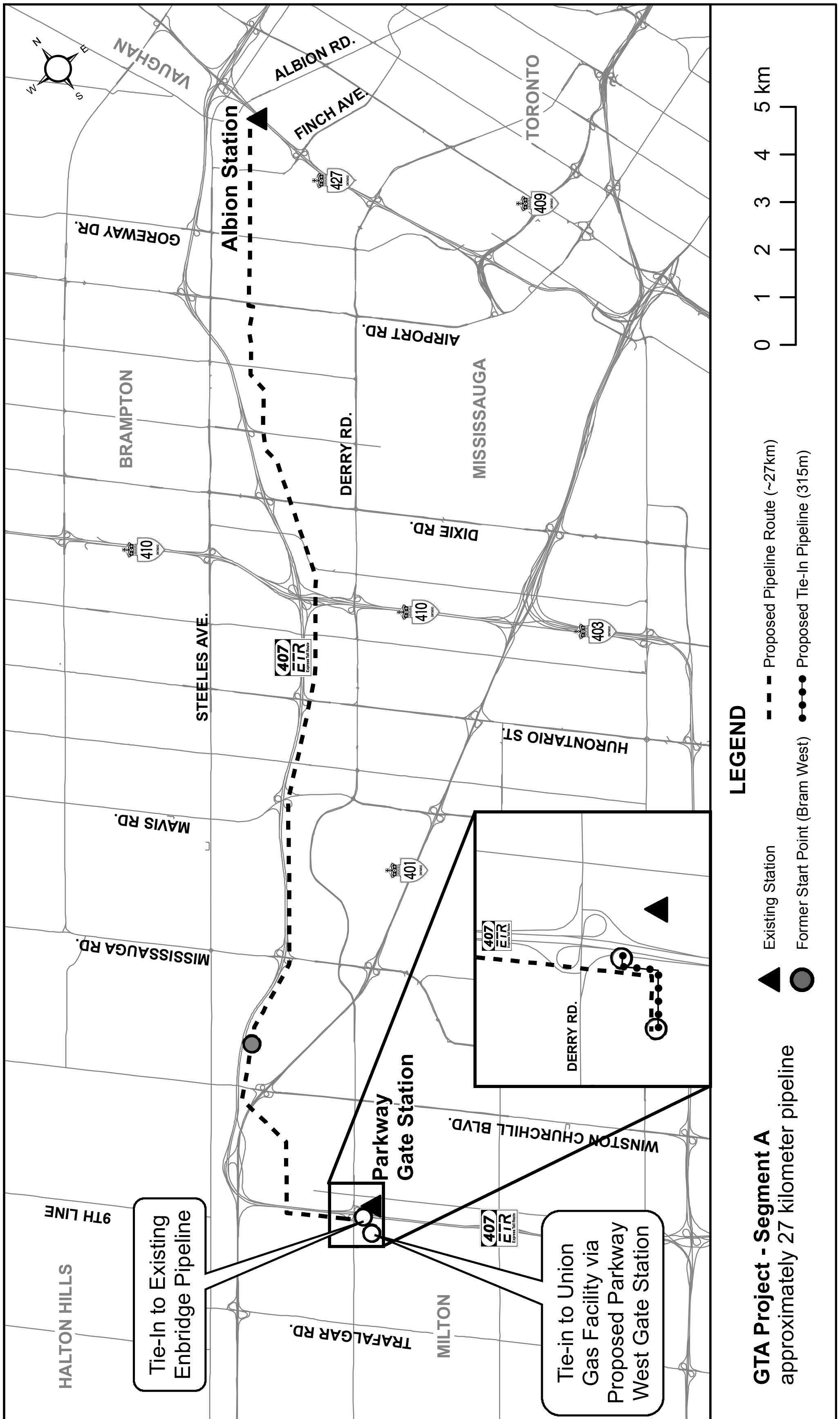
~~*Original Signed by*~~

Scott Stoll

Filed: 2012-12-21
EB-2012-0451
Exhibit A
Tab 2
Schedule 1
Attachment
Figure 1



Updated: 2013-07-22
EB-2012-0451
Exhibit A
Tab 2
Schedule 1
Attachment
Figure 1



PURPOSE, NEED, AND TIMING

Note: Elements of this evidence have been updated through the submission of Exhibit A, Tab 3, Schedule 9 (filed on July 22, 2013).

Introduction

1. The intent of this section is to provide a summary of the purpose of the GTA Project and the needs met through the construction of the proposed facilities. In ~~addition, in~~ Exhibit A, Tab 3, Schedule 8, the justification for bringing forth the GTA Project Application for Leave to Construct to the Ontario Energy Board (the "Board") at this time will be discussed.

2. Segments A and B are described in detail at Exhibit A, Tab 3, Schedule 6. The existing Extra High Pressure ("XHP") infrastructure is further described in Exhibit A, Tab 3, Schedule 2. The GTA Project Influence Area is later described in Exhibit A, Tab 3, Schedule 4. An overview map of the XHP distribution system with the proposed GTA Project facilities is provided in Figure 1. Major pipelines discussed in this Application are also noted on the map, which includes the NPS 36 "Parkway North~~,~~", NPS 36 Mississauga Southern Link ("MSL"), NPS 30 "Don Valley", and the NPS 26 lines.

~~2.~~

Purpose and Need

3. The GTA Project has multiple purposes intended to address multiple needs. At the highest level, the purpose of the GTA Project is to reinforce the XHP system to manage operational risks and meet growth needs, in a prudent manner. The specific elements are detailed below.

~~3.~~

4. The GTA Project will:

    a. Meet customer growth requirements over the period from 2015 to 2025 by reinforcing the XHP distribution network;

~~a.~~

b. Reduce operational risks and enhance safety and reliability by~~;~~:

   i. ~~by improving~~Improving diversity and flexibility of the distribution system through additional looping of single feed XHP lines and providing additional supply sources for the major XHP lines in the GTA Project Influence Area; and

   ii. ~~providing~~Providing the ability to lower pressures on key supply lines;

c. Provide entry point diversity by reducing the dependence upon Parkway Gate Station which currently provides more than 50% of the supply to the GTA Project Influence Area and ~~which~~ does not have alternate means of supply; and

d. Improve supply chain diversity, reduce upstream supply risks and reduce gas supply costs ~~by as much as $500 million~~~~[1]~~ over the period 2015 to 2025.

~~d.~~

5. The following evidence will discuss each of the above elements. Table 1 on the following page provides a summary of the nature of the benefits associated with each element of the GTA Project.

~~[1] Based on market prices, tolls and volume assumptions outlined in Exhibit A, Tab 3, Schedule 5, Tables A1-A3~~

Table 1: Summary of Purpose and Needs Benefits

	Segment A ~~Parkway~~Bram West Interconnect to Albion[2]	**Segment A Parkway ~~Bypass Regulation~~West Gate Station**[3]	**Segment B**[4]	**GTA Project**[5]
Customer Growth	↑		↑	↑↑
Safety and Reliability of XHP System	↑	↑	↑	↑↑↑
Entry Point Diversity	↑	↑		↑↑
Upstream Benefits	↑		↑	↑↑

Customer Growth

~~5.~~6. The Company has an obligation to serve customers in the communities in which it operates. Historic and forecast growth in the GTA Project Influence Area is shown in Table 2~~.~~ provided on the following page. Despite conservation and efficiency gains, the Company's peak day demand has continued to grow over this period, using up reserve capacity in the XHP system. The XHP system in the GTA Project Influence Area was last reinforced in 1992 and subsequent enhancements were driven by the needs of specific large volume customers rather than by organic customer growth. Customer growth and growth in peak day demand are expected to continue for the period from 2015 through 2025.

[2] Segment A – ~~Parkway~~Bram West Interconnect to Albion ~~and the connection to the NPS 36 Parkway North Pipeline~~ considered in isolation from other aspects of the GTA Project.
[3] Segment A – Parkway ~~Bypass Regulation is~~West Gate Station including the tie-in connection to the NPS 36 Parkway North Pipeline considered in isolation from other aspects of the GTA Project.
[4] Segment B considered in isolation from other aspects of the GTA Project.
[5] GTA Project – The relative benefit of the completion of the entirety of the GTA Project as compared to the individual segments.

Table 2: Historic and Forecast Customer Growth

Years	Residential	Commercial	Apartment	Industrial	Total	/u
2004-2014	~~182,449~~151,382	~~16,889~~14,311	~~439~~ 450	~~59~~ 54	~~199,836~~166,197	
2015-2025	~~156,603~~146,672	~~14,843~~13,977	~~793~~ 750	24	~~172,263~~161,423	

~~6.~~7. Absent reinforcement, system pressures at Station B are forecast to decline below the levels necessary to serve customers by the 2015/2016 heating season. Customer growth in the GTA Project Influence Area is forecasted to consist predominantly of temperature sensitive customers, driving forecast peak day demand growth of approximately 190 TJ/d from 2015 to 2025. Market growth is further described in Exhibit A, Tab 3, Schedule 4.

~~7.~~8. In particular, the downtown Toronto core continues to experience significant growth through the increased densification of residential and commercial developments. The growth in the downtown core, which is supplied primarily through Station B, is occurring at the furthest distance from the entry points. In order to maintain adequate inlet pressures at Station B to supply the downtown core and the Portlands Energy Centre ("PEC") additional facilities are required. Segment B will facilitate future needs by increasing the capacity to supply Station B. Exhibit A, Tab 3, Schedule 4 shows detailed information on the forecasted growth in the downtown area. However, the full benefit of Segment B to meet growth will not be available without additional capacity being added to the XHP distribution system upstream of Segment B.

9. Segment A provides the ability to move volumes of gas, up to 800 TJ/day, east from upstream supply sources to Albion Road Station. This supports the additional load being supplied by Segment B and the XHP and HP distribution system

~~8.~~ downstream of the Albion Road Station, in addition to other upstream supply benefits, as outlined in Exhibit A, Tab 3, Schedule 5.

Enhanced Safety and Reliability of the XHP Distribution System

~~9.~~10. In general, the reserve or unutilized capacity in the existing XHP infrastructure is used to accommodate necessary pressure and/or flow reductions required to mitigate downstream vulnerabilities, manage day-to-day maintenance, integrity programs, unplanned events, and balance system flows. Without such capacity, the Company is concerned that significant outages to customers may result from these downstream vulnerabilities. Downstream distribution vulnerabilities are further described in Exhibit A, Tab 3, Schedule 3. The GTA Project improves reliability by providing diversity and flexibility. Diversity is provided by looping two critical XHP lines that are currently single lines. Flexibility is provided by providing dual supply sources to critical XHP lines that bring supply to the downstream distribution system for eventual delivery to customers.

~~10.~~11. The west to east portion of Segment B will alleviate a restriction in the XHP system caused by the existing west-east NPS 26 XHP line. This NPS 26 XHP line is the sole connection in the Enbridge XHP system between the western and eastern part of the GTA Project Influence Area, operates at lower pressure, and is of a smaller diameter than the pipelines it is connected to at either end. As such, the ability to move gas west-east and vice versa across the GTA will be significantly increased with the installation of Segment B. Further information on the current operation of the XHP distribution system is provided in Exhibit A, Tab 3, Schedule 3.

~~11.~~12. The eastern part of the GTA Project Influence Area and the downtown core is currently fed from a single north-south line (NPS 30 XHP Don Valley pipeline) originating at Victoria Square Gate Station and terminating at Station B, with a partial loop that was added in 2008 to serve PEC. The installation of the north-south portion of Segment B provides looping of part of the NPS 30 Don Valley pipeline and provides a second source, Keele/CNR Station for Station B. In conjunction with the associated Buttonville and Jonesville facilities, this improves the diversity and flexibility of delivering gas to the downtown Toronto core and PEC.

~~12.~~13. The installation of the ~~180~~315 m of NPS 36 XHP ~~36~~ pipeline from the new Parkway West Gate Station to the existing NPS 36 XHP "Parkway North" pipeline will provide an alternate supply source into this system providing additional diversity and flexibility in sourcing gas for this pipeline.

~~13.~~14. The installation of the Parkway Bypass Regulation Station will provide additional connectivity between the NPS 36 Parkway North pipeline and the NPS 36 MSL. This, in conjunction with ~~180~~315 m of NPS 36 pipeline, provides an alternate source of supply for these key distribution supply lines.

~~14.~~15. Segments A and B provide additional sources, connectivity and eliminate constraints, thereby improving the ability to deliver large quantities of gas across the XHP distribution system.

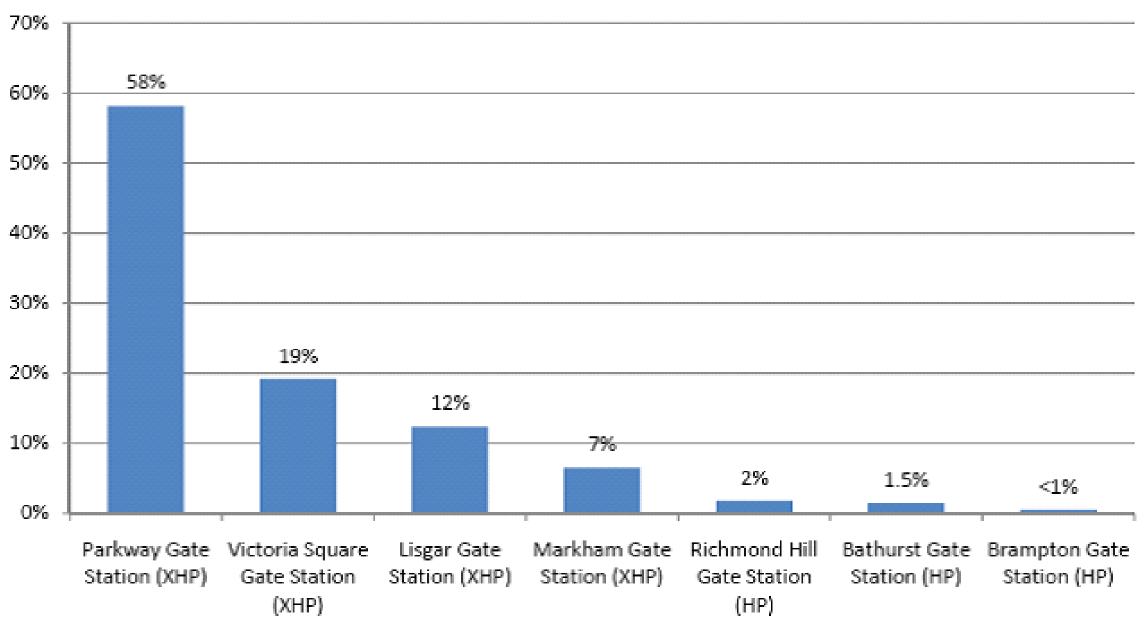
Entry Point Diversification

16. There are currently seven entry points for gas being supplied to the Enbridge GTA distribution system. However, only four of these entry points, Parkway Gate Station, Lisgar Gate Station, Victoria Square Gate Station, and Markham Gate

~~15.~~ Station feed into the XHP distribution system. Entry point vulnerabilities are further outlined in Exhibit A, Tab 3, Schedule 3.

~~16.~~17. As shown in Figure 5 below, the Parkway Gate Station currently provides approximately 58% of the supply to the GTA and surrounding area and Parkway, Lisgar, Victoria Square, and Markham Gate Stations provide approximately 96% of the supply in cold winter conditions.

Figure 5[6]: Composition of Natural Gas Delivery through Gate Stations



~~17.~~18. Further, the remaining entry points, either alone or in the aggregate, do not have the ability to replace Parkway Gate Station in the event of a supply disruption. While the probability of a supply disruption at Parkway is low, the consequences

[6] The figure is based on un-normalized historical average deliveries on cold winter days from both TransCanada and Union Gas at gate stations supplying XHP or HP to the GTA Project Influence Area and surrounding area. The respective percentages are based on total station flows since an outage of a gate station may affect more than the Influence Area considered by this project.

would result in substantial customer losses, greater than 270,000 customers plus PEC, with the existing facilities.

~~18.~~19. An outage of this magnitude has not been experienced in Canada. An outage of 30,000 customers in Sudbury took three days to restore service. Restoration of 70,000 services by National Grid on Long Island that were impacted by Hurricane Sandy has taken at least six weeks. As such, restoration of a more widespread outage would be expected to take significantly longer.

~~19.~~20. Gas supply into the GTA is overly reliant on the Parkway Gate Station. The GTA Project through the facilities contemplated in Segment A will serve to mitigate this risk as, after the facilities are constructed, a supply disruption at Parkway would result in no customer losses.

Upstream Supply Chain

~~20.~~21. Enbridge has an obligation to meet the demand of its customers 24/7/365 by making appropriate arrangements for supply, transport, and storage of natural gas to bring gas to the entry points of its distribution system. The GTA Project will provide the following upstream supply benefits:

a. Improved reliability of upstream arrangements by replacing less secure (short term firm and interruptible) long haul transportation from Western Canada with more secure short haul firm transportation from emerging U.S. North East and Dawn supply; and

b. Create the flexibility to respond to unprecedented changes in traditional supply patterns and increase supply diversity to the Enbridge franchise.

~~21.~~22. North American supply changes have implications for reliability and cost of Enbridge's gas supply portfolio. Enbridge currently procures natural gas from Western Canada, Chicago and the Dawn Hub. These supplies ultimately traverse the TransCanada Mainline and/or the Union Gas system to reach the Enbridge GTA distribution area franchise. Upstream supply and market changes are further outlined in Exhibit A, Tab 3, Schedule 5.

~~22.~~23. The North American natural gas market is currently undergoing unprecedented changes including declines in Western Canadian supplies and substantial increases in new basins in close proximity to the Enbridge franchise.

~~23.~~24. Enbridge's gas supply portfolio has a significant reliance, particularly during peak demand periods, on long haul discretionary services such as Short Term Firm Transport ("STFT"). In addition, direct purchase supply uses STFT and interruptible transport from Western Canada, both of which are a less secure form of transport than Firm Transportation. As such, Enbridge considers the ability to replace STFT and Interruptible Transportation ("IT") with Firm Transportation as an appropriate supply risk mitigation technique and benefit for direct purchase customers.

~~24.~~25. Further, TransCanada is contemplating capacity reductions on the Mainline through conversion to oil and possible pressure de-rates on segments of its pipeline system which are not needed to serve firm transport requirements[7]. These changes will affect the availability of discretionary transport relative to firm transport. Converting long haul discretionary transport to year round long haul firm

[7] Source: Evidentiary record in ~~NEB~~National Energy Board proceeding in RH-~~3~~003-2011

transport will result in less efficient use of capacity and higher costs due to the highly seasonal nature of peak demand on the Enbridge system.

~~25.~~26. Supplies from Marcellus, an emerging supply basin in the U.S. North East and the Dawn Market Hub, supported by firm short haul transport, are ideally suited for sourcing peak and seasonal supply due to their proximity and favourable economics relative to discretionary Western Canadian Sedimentary Basin supplies.

~~26.~~27. The existing upstream infrastructure can bring these emerging supplies economically to Enbridge's Parkway Gate Station. However, these supplies cannot be moved into the Company's distribution system at Parkway Gate Station due to capacity constraints on the existing downstream XHP distribution system, or to other Enbridge gate stations due to capacity constraints on the TransCanada Mainline from Parkway to Maple.

~~27.~~28. As detailed in Exhibit A, Tab 3, Schedule 5, Enbridge expects the GTA Project to provide ~~as much as $500 million in~~its customers gas supply savings.

Discussions with Union Gas and TransCanada

~~28.~~29. The Company has engaged in discussions with both Union Gas and TransCanada.

~~29.~~30. Discussions with Union Gas have centered on Dawn supply, incremental transportation on the Dawn to Parkway system and reliability concerns with supply concentration at Parkway. ~~The~~ Parkway West ~~Project~~project proposed by Union Gas provides the following growth and reliability benefits to Enbridge:

1) Incremental compression as a result of additional volumes contracted from Dawn and Niagara;
2) Back-up feed into Enbridge's system; and
3) Loss of Critical Unit Protection at Parkway West, in the form of standby compression for volumes that are compressed and flow from Union Gas to TransCanada's system for further delivery to the Enbridge franchise. Enbridge is of the view that physical assets such as standby compression at Parkway are necessary to ensure acceptable levels of reliability, relative to the other options discussed in Union Gas' 2013 Rates proceeding, EB-2011-0210, for transportation services that are designated firm.

31. As a result of these discussions, various facilities are proposed in the vicinity of Union Gas' Parkway and Parkway West compressor stations. The facilities provide an alternate feed to Enbridge's existing Parkway Gate Station, Loss of Critical Unit protection, and adequate compression capacity to serve growth and reliability considerations.

~~30.~~32. Discussions with TransCanada have centered on bringing Marcellus supply from Niagara using TransCanada's Hamilton line thus providing diversity of supply and path, increased use of TransCanada's existing infrastructure in the vicinity of Parkway and coordinated planning of infrastructure east of Parkway. TransCanada currently has ~~NPS 36 and NPS 42~~existing transmission lines that ~~parallel~~transport natural gas from Parkway along the ~~proposed routing~~same utility corridor. As a result of ~~Segment A up until these pipelines cross Highway 407 and continue north to TransCanada's Maple compressor facility. The Company has entered into~~ the discussions with TransCanada ~~on two enhancements to~~, the scope of the GTA ~~Project presented in this application:~~ Project's proposed Segment A includes:

1) ~~Interconnection~~An interconnection ("Bram West") with the TransCanada ~~NPS 42~~Mainline at or near the point where the existing lines cross ~~the~~Highway 407~~. This would reduce the length of Enbridge's proposed Segment A by approximately 5 km. Although it would reduce construction costs, it would result in additional transportation tolls on the TransCanada system.~~; and
2) ~~Joint~~Shared use by TransCanada and Enbridge of ~~Segment A, and an expansion by TransCanada~~the pipeline from Bram West to Albion ~~to the vicinity of TransCanada's Maple compressor facility.~~. This would result in a coordinated build out of distribution

~~2)~~ and transmission infrastructure, thus providing benefits to Enbridge's customers and TransCanada's shippers.

~~31.~~33. ~~In the course of its discussions~~Based on anticipated market demand and operating requirements, TransCanada and Enbridge are ~~exploring~~ continuing dialogue regarding the details of shared use of the ~~option of upsizing Segment A~~pipeline segment from ~~NPS 36~~the Bram West Interconnect to ~~NPS 42. Accordingly, subject to successful and timely conclusion of negotiations, Enbridge may amend the application in early 2013 to reflect the change in the origination of Segment A and its potential upsizing from NPS 36 to NPS 42.~~Albion. The ~~potential change resulting from the TransCanada discussions would~~proposed shared usage will meet Enbridge's identified needs, ~~potentially~~ provide economies of scale, and permit a reduction in the project scope ~~to be constructed~~relative to a dedicated sole use pipeline by Enbridge.

~~32.~~34. ~~The change to the origination~~Joint usage of this portion of Segment A does not impact the need for Union Gas' Parkway West facilities. These facilities ~~will~~are still ~~be~~ required to provide a ~~back up~~backup feed to Enbridge's existing Parkway NPS 36 line~~,~~ and ~~to provide~~ adequate compression to serve growth and reliability considerations.

Project Timing

~~33.~~35. Enbridge is seeking a decision to be issued in this proceeding ~~prior to August 1,~~in September 2013 in order to meet the required in-service date. Further information regarding the timing of the activities necessary to complete the GTA Project is provided in

Exhibit A, Tab 3, Schedule 8.

~~34.~~36. Enbridge has brought forth this Application for Leave to Construct at this time because the near term customer growth and network analysis models demonstrate the minimum pressures required to provide reliable service in the downtown core of Toronto in 2015/2016 heating season will not be satisfied. ~~Given the criticality of the minimum system pressure at Station B, and the potential impacts on the supply chain that the proposed facilities mitigate, the Company is of the opinion that the construction should commence so that Segment B can be in-service for January 2015.~~

~~35.~~37. In order to have Segment B in service for ~~January~~the 2015/2016 heating season, construction must begin no later than ~~August 2014 as~~January 2015 and the design, procurement, and permitting process will take more than one year to complete.

~~36.~~38. Segment A provides significant ratepayer gas supply benefits and November 1, 2015 is the earliest date in which those benefits can begin to accrue. The full benefits of Segment B can only be realized when Segment A is in-service. ~~Further,~~Segment A is also required to meet the ~~coordinated construction schedule provides savings and optimizes the benefits while meeting the permitting and construction constraints.~~commitments for TransCanada as outlined in Exhibit E, Tab 1, Schedule 2.

~~37.~~39. A project of this nature has ~~significant~~substantial lead time requirements which cannot be ~~significantly~~easily shortened. Failure to initiate the project in a timely manner creates unacceptable risk to providing safe and reliable service.

~~38.~~40. The timing is also influenced by the external factors described above in the Upstream Supply Chain section which create supply uncertainties with respect to Enbridge's current gas supply portfolio.

Summary

~~39.~~41. The GTA Project will:

a. Meet customer growth requirements over the period from 2015 to 2025 by reinforcing the XHP distribution network;

b. Improve safety and reliability of the distribution system by eliminating existing constraints in the XHP distribution system;

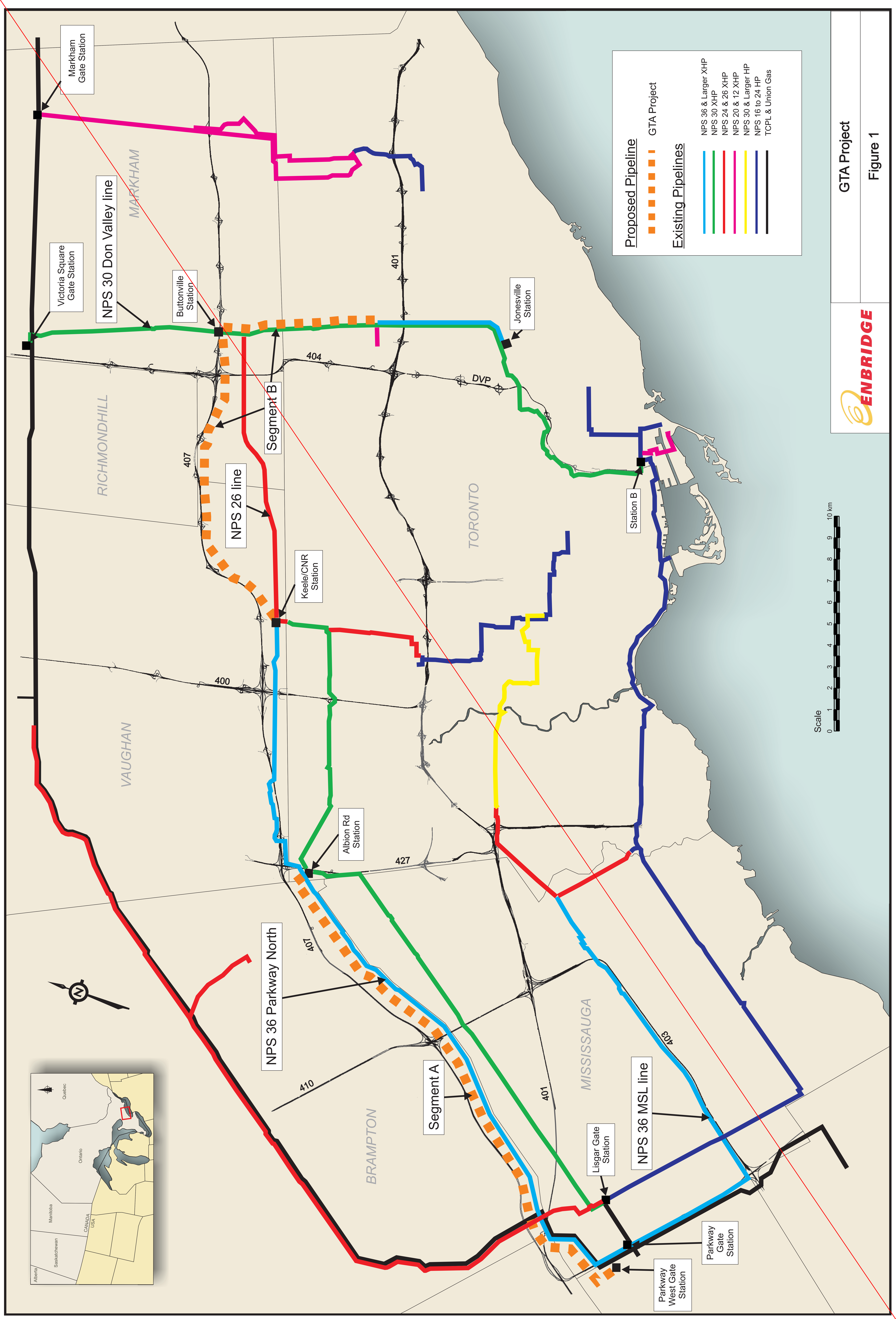
c. Provide entry point diversity by reducing the dependence upon Parkway Gate Station; and~~,~~

d. Improve upstream supply diversity and risk mitigation.

~~d.~~

~~40.~~42. While some benefits will be provided by each of the individual components, the greatest benefits will be realized by completing the GTA Project as described herein.

Filed: 2012-12-21
EB-2012-0451
Exhibit A
Tab 3
Schedule 1
Attachment
Figure 1



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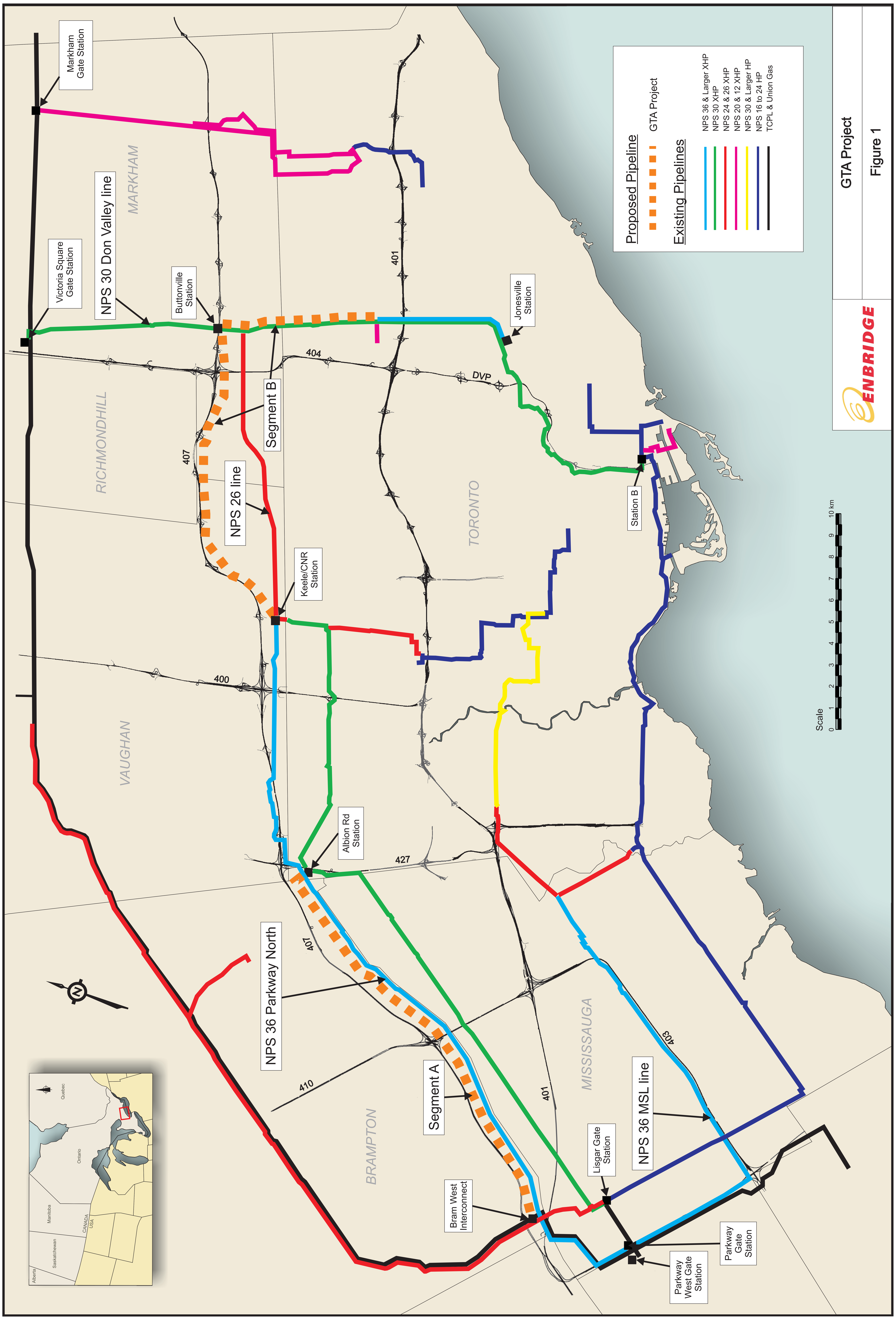
EB-2012-0451
Exhibit A
Tab 3
Schedule 1
Attachment
Figure 1



HISTORY OF NATURAL GAS SUPPLY IN THE GTA

1. The purpose of this evidence is to provide an explanation of the evolution of the XHP and HP infrastructure supplying the GTA and to assist in understanding the location, function, and reliance on these important assets. XHP pipelines carry the most capacity in the distribution network as a result of their higher pressures. The various pressure classes are further described in Exhibit A, Tab 3, Schedule 3.

2. Enbridge has been delivering energy in the GTA for over 160 years. From its start in 1848 until 1954 Enbridge distributed manufactured (coal) gas to its customers. Prior to the introduction of natural gas to Toronto in 1954, manufactured gas was delivered through Low Pressure ("LP") cast iron mains, later augmented with Medium Pressure ("MP") mains, originating at two gas manufacturing plants, Station "A" at Front and Parliament Streets and Station "B" at Eastern and Booth Avenues to the east of downtown Toronto.

3. Currently, Enbridge has a very high penetration rate in the areas its serves and its customers are largely temperature sensitive.

4. More than half of Enbridge's customers reside in the GTA and are served off a single integrated network described in the rest of this section. The evolution of the XHP and HP infrastructure supplying the GTA was driven by customer growth, collaboration with Enbridge's upstream suppliers on supply and optimal use of existing infrastructure, as well as the prudent planning and management of its distribution system.

5. In the early 1950's, the Tennessee Gas Pipeline began delivering natural gas to the Buffalo, New York area. By the end of 1954 this natural gas transmission line had

been extended across the Niagara River to Mississauga, the western border of the Company's GTA franchise area. This line was owned by Western Pipelines, a predecessor of TransCanada Pipelines Limited ("TransCanada"), and leased to Niagara Gas Transmission Company. Enbridge took the first deliveries of natural gas at Sheridan Gate Station, the Company's first gate station, located near the intersection of Winston Churchill Boulevard and Sheridan Park Drive.

6. In order to supply the core distribution area in Toronto, natural gas had to be transported from Sheridan Gate Station to Stations "A" and "B". This was facilitated through the construction of a NPS 20 pipeline along Lakeshore Boulevard in 1954 as shown in Attachment, Figure 1. The distribution system was converted from manufactured gas to natural gas by 1955 and the TransCanada line (Western Pipelines) remained the only source of natural gas supply until the end of 1958.

7. By the end of 1958 TransCanada had completed the construction of its transmission pipeline (the "Mainline") from Empress, Alberta to Toronto and Montreal. Enbridge took its first deliveries of Western Canadian natural gas from the TransCanada Mainline at an interconnection at Sheridan Gate Station.

8. In the same year, Union Gas Limited ("Union Gas") had also completed the construction of the 229 km NPS 26 Trafalgar Line between Dawn and the Trafalgar Compressor Station, located just west of Toronto in Mississauga. This new line provided Union Gas with a connection both to TransCanada and to Enbridge through its newly constructed Lisgar Gate Station, located near Winston Churchill Boulevard and Derry Road in Mississauga. This line facilitated upstream access to the Union Gas "Dawn Hub", which provided gas supply from numerous supply basins, such as those located in Western Canada, and the lower 48 states. In addition, Union Gas' Dawn to Trafalgar Line also facilitated the use of natural gas

storage facilities for load balancing purposes. Natural gas was delivered to underground storage pools near Sarnia when not required during summer months and drawn upon in winter months to meet seasonal and peak day demands.

9. Union Gas had been developing underground storage pools since the 1940's, and in 1958, Enbridge entered into its own storage development. Tecumseh Gas Storage Limited, a jointly owned subsidiary of Imperial Oil Limited and Enbridge, began operating gas storage pools also in Sarnia. To better utilize its storage gas facilities, Enbridge constructed a NPS 20 pipeline linking Lisgar with Sheridan Gate Station. This facilitated the delivery of storage supplies to the NPS 20 pipeline along Lakeshore Boulevard which was the major source of supply into Toronto until 1961. This location of this pipeline and the natural gas infrastructure by the end of 1958 is shown in Attachment, Figure 2.

10. As a result of the abundance of deliveries from Western Canada, contracts importing natural gas from United States through the Tennessee Gas Pipeline were terminated and the flow in the Tennessee Gas Pipeline was reversed. Gas supply contracts were initiated to export natural gas to the United States.

11. In 1959, Markham Gate Station became the second interconnection with TransCanada's Mainline. This station, located near 9th Line and Elgin Mills Road East in Markham, was constructed to bring gas supply into the Scarborough area via a new NPS 16 pipeline constructed the same year.

12. In the early 1960's, the first phase of a NPS 30 pipeline system was constructed along Derry Road from Lisgar Gate Station toward the then northern perimeter of the Toronto market area. The pipeline continued past Albion Road Station towards

Highway 400. This system could move large quantities of gas at higher pressures across the top of the urban area to feed into the distribution system at key locations.

13. By 1967, a subsequent construction phase extended the NPS 30 pipeline from the northern perimeter of Toronto to Vaughan, and then a NPS 26 pipeline was continued further east to Markham as shown in Attachment, Figure 3. The NPS 26 would eventually tie into the NPS 30 Don Valley pipeline described in the next paragraph.

14. In 1971, a NPS 30 pipeline was constructed to bring natural gas supply from Victoria Square Gate Station, located near Woodbine Avenue and 19th Avenue in Markham, south to Station B in downtown Toronto. This pipeline is known as the "Don Valley" pipeline since it runs parallel to the Don Valley Parkway in sections of its route. The major pipeline infrastructure in 1971 is shown in Attachment, Figure 4. The pipeline was constructed predominantly in the Ontario Hydro corridor and was originally installed to serve the R.L. Hearn Generating Station, Canada's first steam turbo-generator. Since its commissioning in 1951, the R.L. Hearn Generating Station was a coal powered facility until it was converted to natural gas in 1971. The gas demand required by the Hearn facility and customer growth necessitated the additional capacity offered by the Don Valley pipeline. The pipeline commissioning effectively completed the first Extra High Pressure ("XHP") loop around the GTA and thus became a critical source of supply for the distribution system.

15. By 1977, the distribution facilities supplying gas from west to east had reached capacity. Downstream takeaway capacity from Lisgar Gate Station in Mississauga was limited relative to total receipts from Union Gas. Rather than install additional facilities, Enbridge entered into an agreement with Union Gas and TransCanada to have a portion of the Company's storage volumes compressed by Union Gas and

injected into TransCanada's system for transportation. An equivalent volume would then be delivered by TransCanada to Enbridge at the recently built Victoria Square Gate Station in Markham. The agreements with Union Gas and TransCanada are collectively known as Storage Transportation Service ("STS"). This arrangement made use of the excess capacity that existed at the time on both Union Gas' and TransCanada's systems and allowed Enbridge to postpone the reinforcement of its major facilities. Attachment, Figure 5 shows the transportation route of the natural gas purchased from Union Gas, transported along TransCanada's infrastructure, and delivered to the Enbridge franchise via Victoria Square Gate Station. The figure represents the STS path in 1977. Today, the STS path begins at Parkway Gate Station, a facility that is described in Paragraph 20 below, and has delivery points across the Enbridge franchise areas.

16. Through the late 1970's and early 1980's, the distribution system continued to operate at capacity, hence Enbridge contracted for additional STS volumes to offset the capacity shortfall. Since the original agreement, the contracted STS volumes required each year varied based on customer growth and capacity expansion through continued XHP system reinforcement.

17. The R.L. Hearn Generating Station was decommissioned in 1983 and the capacity in the Don Valley pipeline was used to supply customer growth in the City of Toronto and surrounding area over the next few decades.

18. In the mid-1980's, as the distribution system continued to expand to meet customer growth of the GTA, it was no longer feasible to reinforce the areas with short sections of HP pipe due to constraints on the XHP system. Lisgar Gate Station, originally located in a rural area, became encroached by urban development and was unable to meet the continued demand due to its limited capacity and

undesirable location for expansion. In addition, Enbridge faced a shortfall in STS availability from Union Gas. Enbridge had relied on the surplus capacity and contracted STS on a short-term basis, but was now forced to seek a long-term solution.

19. The long term solution was to create a new entry point and associated XHP delivery infrastructure rather than increasing reliance on Lisgar Gate Station. The solution consisted of constructing two new XHP pipeline paths, one towards the northern area of the GTA and the other towards the southern area, and a new supply point (or exchange point for STS). The proposed infrastructure satisfied the overall system requirements of enhancing distribution capacity and security of supply. The additional supply point was placed in the area of the existing Union Gas and TransCanada pipeline infrastructure near Derry Road and 9th Line in Mississauga (today known as Parkway Gate Station) since no other location in the distribution area could achieve the same system benefits. Due to the magnitude of the northern reinforcement, the project was managed in phases, and therefore, the additional supply point and pipeline reinforcement became part of a broader project known as the “Parkway Belt”. Through this phased approach, the project could be evaluated, managed, and timed to meet distribution system upstream and downstream requirements.

20. In 1986, Parkway Phase 1 commenced construction of Parkway Gate Station and a NPS 36 XHP pipeline. This NPS 36 pipeline runs east along the then northern perimeter of the GTA primarily through the designated Parkway Belt utility corridor to the new Albion Road Station located at Highway 427 and Albion Road. Upon completion of Phase 1, Parkway Gate Station became the third major natural gas supply source to the GTA.

21. In 1990, Parkway Phase 2 commenced construction of a NPS 36 XHP pipeline from Albion Road Station further east along the same designated Parkway Belt utility corridor to the new Keele/CNR Station located near Keele Street and Steeles Avenue West. The major XHP pressure distribution pipelines as they existed in 1991 are shown in Attachment, Figure 6.

22. In 1991, construction commenced on the MSL pipeline, which consisted of approximately 23 km NPS 36 XHP main and 5 km NPS 24 XHP main. The NPS 36 XHP MSL pipeline parallels the existing Highway 407 to Highway 403, and then parallels Highway 403 to just west of Etobicoke Creek at a valve compound near Audubon Boulevard. A NPS 24 XHP pipeline then travels south and terminates at West Mall Station near the Queensway and the West Mall. The MSL was required to meet customer growth and concerns with security of supply.

23. In 1992, construction began on further southern reinforcement through installation of NPS 24 XHP and NPS 30 HP pipelines and related facilities. The NPS 24 XHP pipeline extended from the valve site near Audubon Boulevard in Mississauga to Martin Grove Station near Martin Grove Road and Eglinton Avenue in Etobicoke. The NPS 30 HP pipeline was constructed from the new Martin Grove Station in Etobicoke to an existing NPS 24 HP line near the intersection of Harvie Avenue and St. Clair Avenue West in the City of Toronto. This project was known as the Metro West Reinforcement project which was required to meet the gas demand requirements for customer growth during the 1993 to 2012 timeframe in the Toronto and surrounding area.

24. In 1993, the Company initiated planning on the Parkway Phase 3 to construct a NPS 36 XHP pipeline from the Keele/CNR Station to the existing NPS 30 XHP Don Valley line. Following the additional procurement of STS capacity and the introduction of

~~24.~~ the first Demand Side Management program in 1995, further system reinforcement through Parkway Belt Phase 3 was postponed. The Parkway Phase 3 was again contemplated in the 2007 Rate Case; however, the Company was successful in procuring additional Firm Transportation capacity from Parkway to Central Distribution Area ("CDA") on the TransCanada system. Consequently, the project was again postponed.

25. In 2008, a natural gas fired power plant, Portlands Energy Centre ("PEC"), was constructed east of downtown Toronto to meet the increasing electricity demands of Ontario. NPS 36 and NPS 20 XHP reinforcement pipelines were constructed to match the incremental capacity required by the plant. The NPS 36 XHP was installed through the existing Hydro corridor paralleling Victoria Park Avenue from just north of Sheppard Avenue in Scarborough to Jonesville Station, just north of Eglinton Avenue East, in Toronto. The NPS 20 XHP was constructed from Station B near the intersection Eastern Avenue and Broadview Avenue and ran to the plant's location.

26. The major pipeline infrastructure supplying the GTA and the corresponding decade of installation is shown in Attachment, Figure 7.

27. Enbridge has not had a major upgrade specific to the GTA Project Influence Area to support demand growth and reliability for 20 years and in that time the number of customers in the Enbridge franchise has almost doubled from 1.1 million (1992) to 2.0 million (2012) customers, with ~~more than~~almost half of the existing customers in the area supplied by the GTA Project Influence Area. The GTA Project Influence Area ~~has surpassed~~is projected to surpass supplying 1.0 million customers within this area in ~~2007~~2014. The high rate of customer growth and intensification of /u /u

customers within the GTA has resulted in ~~more than~~almost half of Enbridge's customers residing within GTA Project Influence

~~27.~~ Area and served off the integrated XHP network described in this section. The GTA Project Influence Area is described in Exhibit A, Tab 3, Schedule 4.

28. The peak day natural gas flow through Enbridge's GTA XHP system exceeds 2.4 PJ[1], which on an hourly basis is equivalent to 95%[2] of highest electrical generation output ever achieved in the province of Ontario. The continued reliability of the GTA system is of primary importance given the reliance on natural gas, the large number of customers served on a single integrated network, and the manual restoration process associated with outages in natural gas networks.

29. The GTA is expected to experience continued growth and intensification. This proposed project is the next development in the continued evolution of the Company's distribution system. Further information is provided in the subsequent Schedules.

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[1] Based on peak day actual flow through Enbridge's XHP system supplying the GTA Project Influence Area.
[2] Record Peak in Ontario based on the Independent Electricity System Operator ("IESO") website (http://www.ieso.ca/imoweb/siteShared/demand_price.asp?sid=ic). 1 GJ is equivalent to 0.28 MW hours of electricity based on the National Energy Board's website (http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/sttstc/nrgycnvrsntbl/nrgycnvrsntbl-eng.html).

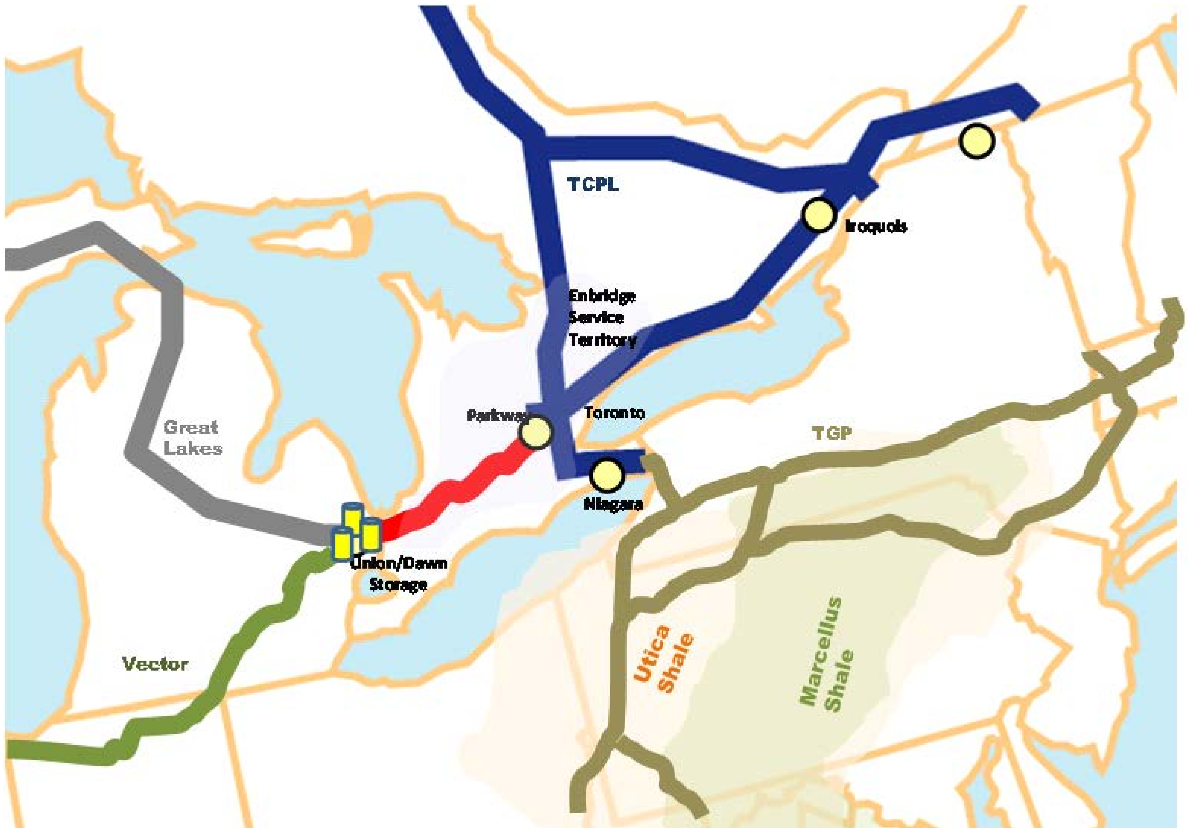
OPERATION AND LIMITATIONS OF EXISTING FACILITIES

1. The purpose of this evidence is to describe current operations and the inherent operational challenges the Company faces to ensure the continued safe and reliable delivery of natural gas without system reinforcement. These challenges relate to:
    - the Company's ability to continue to attach customers and maintain the reliable delivery of gas to its firm customers;
    - the Company's ability to address operational risks and constraints associated with distribution system and gas supply entry points; and,
    - the Company's ability to source and or take deliveries from new and emerging supply basins to the benefit of customers.

Current Operations

2. Enbridge currently procures natural gas from Western Canada, Chicago and Dawn. The supplies are ultimately transported to Enbridge's franchise area by TransCanada's Mainline and/or Union Gas' Dawn to Parkway system and delivered to one of the Company's gate stations. A map of the upstream supply system is shown in Figure 1.

Figure 1: Map of Upstream Supply System – Current and Potential Supply Paths



3. Gate stations interconnect to TransCanada and Union Gas transmission pipelines and supply the downstream XHP and HP distribution systems. Once in the distribution system, downstream XHP distribution pipelines move large volumes of gas from gate stations to key points across the system for further distribution. These key points are localized district stations where pressure is regulated down for distribution on the HP and lower pressure networks for ultimate delivery to

customers[1]. A few industrial customers such as large power generation facilities are served directly from the XHP system due to their pressure requirements.

4. The XHP distribution network consists of 221 km of large diameter XHP mains (NPS 24 or larger). Figure 1 shows a map of XHP and HP pipelines within the GTA. For reference, this map shows XHP and HP mains between NPS 16 to 36 in diameter. Station B is one of 11 large district stations in the GTA and is the furthest from a gate station or interconnections with upstream supply. It delivers XHP to PEC and HP gas to the downtown Toronto core and surrounding area, which further supplies the extensive IP network. For these reasons, Station B often experiences the lowest system pressures in the XHP network.

5. The XHP distribution system is the highest pressure class. It is considered to be the backbone of the distribution system since it brings supply to the thousands of kilometres of lower pressure mains in the system, much like the highways feed arterial roads and city streets. Adequate capacity in the XHP network is a prerequisite for maintaining minimum system pressures throughout the other pressure classes. Therefore, this pressure class will be the primary focus of this evidence.

6. The XHP distribution system in the GTA is predominantly fed by four gate stations: Parkway, Victoria Square, Lisgar, and Markham Gate Stations.

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[1] For reference, Enbridge defines its pressure classes with operating pressures as follows: XHP – above 1200 kPa (175 psig); HP – 450 to 1200 kPa (65 to 175 psig); Higher Pressure Polyethylene (“HPPE”) –140 to 690 kPa (20 to 100 psig); Intermediate Pressure (“IP”) – 70 to 440 kPa (10 psig to 64 psig); Medium Pressure (“MP”) – 20 to 80 kPa (3 to 12 psig); and, Low Pressure, Regulated (“LP”) – 3.5 to 14 kPa (0.5 to 2.0 psi).

- Parkway Gate Station is the largest gate station. It is primarily supplied by Union Gas' Dawn to Parkway transport system, but has some capability to be fed by TransCanada. Parkway supplies the GTA system from the west via two NPS 36 XHP pipelines, the northern Parkway North pipeline and the southern Mississauga Southern Link ("MSL") pipeline[2].

- Victoria Square Gate Station is the second largest gate station. It is supplied solely by TransCanada. Victoria Square provides supplies to the GTA from the north via the NPS 30 XHP Don Valley pipeline[3]. The Don Valley pipeline is the only supply of XHP gas to the downtown core and is the only pipeline that currently has a pressure rating capable of serving PEC.

- Lisgar Gate Station is the oldest operating gate station in the GTA. Lisgar operates as a gate station in the winter and as a district station during the rest of the year. It is solely supplied by Union Gas during winter demand conditions and supplies the downstream system from the west via NPS 30 XHP, NPS 24 XHP, NPS 20 HP pipelines[4]. Lisgar receives supplies from the XHP network downstream from Enbridge's Parkway Gate Station via the NPS 24 XHP line during the non-winter months.

- Markham Gate Station is solely supplied by TransCanada. It connects into an XHP pipeline which supplies the very eastern part of the GTA. However, the

[2] The north NPS 36 XHP from Parkway Gate Station currently operates up to 3344 kPa (485 psi). The South NPS 36 XHP from Parkway Gate Station currently operates up to 2416 kPa (350 psi).
[3] The NPS 30 XHP line supplied south from Victoria Square Gate Station currently operates up to 3103 kPa (450 psi).
[4] The NPS 20 HP line supplied from Lisgar Gate Station currently operates up to 1200 kPa (175 psi) and the NPS 30 XHP line up to 1896 kPa (275 psi). The NPS 24 XHP line is tied into the same network as Parkway Gate Station's NPS 36 XHP Parkway North line, and therefore operates up to 3344 kPa (485 psi).

Markham supplied system is essentially isolated from the rest of the XHP system that supplies the GTA because there is no XHP pipeline that ties the two XHP systems together.

7. The XHP distribution system is an integrated network. During off-peak conditions, the geographic area typically supplied by one gate station may be partially supplied by another gate station depending on weather and operating conditions. However, as the temperature approaches peak day conditions, the GTA network begins to operate more like three single source networks (with supply from the three largest gate stations) as opposed to an interconnected system. The gas flow during peak conditions is schematically represented in Figure 2. The general areas supplied by these gate stations during cold winter conditions is schematically represented in Figure 3.

8. Enbridge does not operate any compression facilities within its distribution areas; consequently natural gas flows only from higher pressure pipes to lower pressure pipes through interconnecting district stations as previously mentioned.

Obligation to Attach Customers

9. The Company has an obligation to attach customers within an area that is already being served by natural gas. Approximately ~~1.1 million~~980,000 customers, out of 2.0 million customers ~~frachise~~franchise-wide, are located within the GTA Project Influence Area[5]. The GTA is well served with natural gas infrastructure in most city streets. In this type of area, customer additions are often attached through a new service and meter off an existing gas main. Once the capacity serving the geographic customer base is consumed, it may require reinforcement. Apart from /u

[5] The GTA Project Influence Area is described in Exhibit A, Tab 3, Schedule 4.

large customers that may be served directly off the XHP system, the XHP distribution system is not often reinforced. The larger diameter and higher pressure results in discrete but significant capacity additions that are capable of serving several years of organic growth.

10. The Company analyses its distribution system on a regular basis to assess its capability to meet anticipated future operating conditions. At a minimum, the network must be capable of maintaining adequate pressures to meet all firm customers' demands under peak day conditions. If system pressures are forecast to be below the minimum required pressures, main reinforcements may be required to add capacity to the system to support customer growth. Reinforcements are also sometimes required to address bottlenecks in the system. These reinforcements often occur by paralleling or looping existing infrastructure, a common practice among utilities.

11. As noted in Exhibit A, Tab 3, Schedule 2, the XHP system has not been reinforced since 1992 for organic growth other than for specific large volume customers. The area served by the GTA Project is experiencing densification of residential development through the redevelopment of brown-field sites and other low density sites. For example, Toronto currently has 15 buildings under construction that are 150 m or greater in height (44 to 70 floors), of which 12 are residential, one is residential-office, one is office, and one is a hotel. In 2015, Toronto will have four times as many tall buildings (greater than 150m) than it had in1995[6]. Growth in the downtown core served by Station B is schematically shown at Exhibit A, Tab 3, Schedule 4. The distribution system supplying the GTA Project Influence Area will

[6] Source: Council on Tall Buildings and Urban Habitat Journal, 2012 Issue IV. In 1995, Toronto had 11 buildings greater than 150 m in height. In 2015, Toronto will have 45 buildings greater than 150 m in height.

reach its peak day capacity in 2015 as evidenced by system forecast models dropping below minimum operating pressures at Station B[7]. Increasing densification also has implications for reliability planning as explained in the following section.

Safe and Reliable Delivery of Natural Gas

12. The following section describes the framework used by the Company to assess reliability. Criteria for assessing reliability requirements typically focus on the criticality of the need (essential versus non-essential), process, and timelines for restoration of service.

13. Energy delivery is an essential service, and natural gas in particular is relied upon by the majority of Ontario residents as a primary source of energy. As mentioned in Exhibit A, Tab 3, Schedule 2, the peak day natural gas flow through Enbridge's GTA XHP system exceeds 2.4 PJ/day. On an hourly equivalent basis of 0.12 PJ/hr, this equates to 95%[8] of the highest electrical generation output ever achieved in the province of Ontario. In addition, the XHP network provides natural gas to 775 MW[9] of large scale power generation in the GTA. PEC is supplied directly from the XHP system, downstream from Station B[10], and generates up to 550 MW of electricity.

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[7] The minimum required inlet pressure to Station B is 1551 kPa (225 psi).

[8] Record Peak in Ontario based on the Independent Electricity System Operator ("IESO") website (http://www.ieso.ca/imoweb/siteShared/demand_price.asp?sid=ic). 1 GJ is equivalent to 0.28 MW hours of electricity based on the National Energy Board's website (http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/sttstc/nrgycnvrsntbl/nrgycnvrsntbl-eng.html).

[9] The 775 MW of large scale power generation includes Portlands Energy Centre at 550 MW, Greater Toronto Airport Authority ("GTAA") at 117 MW, and TransAlta at 108 MW.

[10] Station B's inlet pressure is required to maintain the minimum contractual 1,379 kPa (200 psi) delivery pressure to serve PEC.

14. Unlike electricity which can be automatically restored, customer outages pose a particular challenge on natural gas systems due to the need for manual restoration of service. First, the natural gas service must be manually turned off at the meter to “make safe”. Gas cannot be reintroduced into the distribution system until it has been confirmed that all meters have been turned off. Once it has been confirmed and natural gas pressure in the main has been restored, each of the customer’s natural gas appliances must be inspected and relit prior to turning the gas service back on. This requires each customer to be visited twice during the outage. Depending on the size of the outage and available resources, it could take days, weeks or even months to safely restore service. For example, a manual restoration process to isolate and relight 25,000 to 50,000 customers could take between 6,600 to 13,200 person hours (performed by gas technicians)[11]. Industry outage examples of this magnitude are described below.

15. Large outages may require support from other utilities through the Canadian Gas Mutual Aid Assistance Agreement. This Agreement is a ready mechanism for Canadian natural gas industry companies to assist each other during emergencies. This type of agreement was recently used to respond to Hurricane Sandy. Hurricane Sandy struck the East Coast of the United States on the 29th of October, 2012, causing widespread damage across the eastern seaboard. One of the hardest hit areas was Long Island, New York. National Grid, a gas utility with customers in Long Island, had 70,000 gas services affected, leading to 200,000 customers being impacted by the storm. The recovery efforts began as soon as it was safe, with mutual aid assistance arriving from all parts of the United States and

[11] Based on Enbridge’s Emergency Procedures Manual, it is estimated that a gas technician can turn off 15 residential meters per hour and relight 5 residential meters per hour. Therefore, for example, 25,000 residential customers would take approximately 1,600 person hours to turn off meters and 5,000 person hours to relight the affected customers.

Eastern Canada. More than 570 mutual assistance crews from 46 companies took part in the restoration effort. In Suffolk County alone, over 120 gas crews were working on the recovery. As at December 14th, service had not been restored to all affected customers, nearly six weeks after the storm had struck.

16. In 2011, production losses in Texas resulted in an outage to 50,000 customers in parts of Texas, Arizona, and New Mexico. In this instance, restoration of service was completed in one week, as outlined in a Federal Energy Regulatory Commission (FERC) report "Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 20011 – Causes and Recommendations".

17. An extended period of time without gas service in cold winter conditions would cause an immediate concern to residential customers due to loss of heat and risk of damage to homes (i.e., burst water pipes). At 35 DD, or -17 degrees Celsius, a typical home would drop below 0 degrees Celsius in approximately 14 hours, while at 19 DD, or -1 degrees Celsius, a typical home would drop below 0 degrees in two days[12]. Municipalities would likely need to invoke warming centers with another form of heat, emergency response plans, and potential evacuation of influenced areas.

18. Reliable service requires a robust supply chain. Flexibility, diversity, and the ability to manage operational risk must be prevalent in all aspects of the supply chain – downstream distribution, entry points into the distribution system, and upstream supply.

- <u>Flexibility</u> is the ability to manage reliability in changed circumstances both short term and long term.

[12] Based on guidelines in Enbridge's Emergency Procedures Manual.

- Diversity is the ability to manage reliability through dual or more supply sources and paths.
- Operational risk management is the ability to recognize and mitigate threats to the safety and reliability of continued service.

19. These elements are managed differently in each aspect of the supply chain. On the infrastructure front, both downstream distribution and entry points must be assessed for strengths and limitations, requirements for integrity management and the consequences of mechanical or supply failure. On the upstream supply front contracts must ensure diversity of suppliers and low risk of default. Ensuring that customer demand is met 24/7/365 requires a robust gas management system and processes that facilitate accurate demand forecasting, enable adequate supply to be procured and dispatched as needed, and permit real time monitoring of pressures and/or flow at key locations as a test of supply/demand balance.

20. The reliability of Enbridge's distribution system has become increasingly constrained. Customer growth has consumed available capacity within the XHP network since the last time it was reinforced in 1992. As a result, the XHP system has a diminished ability to provide operational flexibility, diversity, and risk mitigation measures, particularly in the winter months. These limitations are depicted in the order of distribution, entry point, and upstream supply in the Table 1 below and described in the remainder of this schedule.

Table 1: Summary of Limitations in the Supply Chain and Reliability Consequences

	Diversity Limitation	Flexibility Limitation	Operational Risk Limitation	Supply Consequence
Distribution	Single XHP line serving downtown Toronto core. Single XHP link between western and eastern parts of the GTA Project Influence Area.	Inadequate ability to manage planned and unplanned maintenance and integrity work in higher demand periods.	Limited ability to reduce pressures in order to reduce risk and maintain supply during winter period.	**Loss of minimum inlet pressure at Station B results in outage to firm customers at a 35 DD.**[13]
Entry Point	More than 50% of volumes from a single gate station.	Limited reserve capacity to compensate for reduced flows from a gate station.	Inability to maintain customers in the event of gate station failure in winter.	**Loss of Parkway results in outage of approximately 270,000 residential customers plus PEC at a 35 DD.**
Upstream Supply	Diversification opportunities are currently limited by upstream transport capacity.	Limited ability to replace lost supply due to constraints in upstream transport capacity.	Reliance on non-renewable long haul transport, and lack of Loss of Critical Unit (“**LCU**”) protection for short haul transport creates portfolio risk in winter time.	**A 300 to 400 TJ/d loss of supply results in an outage of approximately 150,000 to 225,000 customers at a 41 DD.**[14]

[13] The results of the supply consequence are based on a single valve closure in network simulations. This type of network analysis was performed to understand system vulnerabilities under the respective scenarios and does not represent projected customer losses in conditions of a gas release (i.e. pipeline damage). Customer losses as a result of a gas release are expected to be higher due to the drawdown of the network.
[14] These customer losses are approximate and were determined using the “Enbridge Load Shed Report”, which is a load shed plan developed to respond to a supply shortfall. The customer losses resulting from this scenario assumes that PEC is not consuming gas.

Limitations with Downstream Distribution

21. Daily operation of the GTA's XHP distribution system involves the intregration, coordination, and management of the following activities:

    - Integrity activities, such as inline or visual inspections, non-destructive testing, or corrosion evaluations;
    - Daily maintenance work, such as welding repairs and welding connections to the line;
    - Planned events, such as temporary or permanent relocations requested by municipalities under franchise agreements; and,
    - Unplanned events, such as third party construction activities and pipeline damages.

    The safe execution of the maintenance, inspection, and relocation activities requires flow and/or pressure reductions. Pressures are lowered below specific operating stress levels to perform work and are sometimes restricted to 80% of the normal operating pressure until further inspections and/or repairs can be performed. The system requires adequate diversity and flexibility for the rerouting of supply resulting from capacity losses due to these pressure and flow restrictions.

22. As shown in Figures 2 and 3, while the western part of the GTA has multiple lines extending east from the vicinity of the Parkway and Lisgar Gate Stations, the eastern part of the GTA has two critical XHP pipelines that lack diversity.

23. The NPS 30 Don Valley Pipeline is the only XHP pipeline extending south from Victoria Square Gate Station to the downtown Toronto core and surrounding area. It supplies a high concentration of customers, it is the only source of supply for PEC, and it also serves the largest economic centre in Canada. As it exists today, if this pipeline experienced a pipeline defect or damage in winter months, significant

customer outages would immediately occur. The Company would have to either temporarily reduce operating pressures or shut down the line. At a minimum, supply would have to be terminated to PEC, which is the equivalent to the demand of 100,000 residential customers. In the case of pipeline damage, a significant number of customers may lose gas supply, and as noted previously, would require two sites visits in order to both "make safe" and restore service once the system issue is remediated. The area served by Station B also has the highest density of customers in the Enbridge franchise area.

24. The NPS 26 line is currently the only XHP line that provides the ability to connect the western and eastern parts of the distribution system. The NPS 26 line operates at 2586 kPa (375 psi), is smaller in diameter and operates at a lower pressure than its interconnecting pipelines; the NPS 36 Parkway North operates up to 3344 kPa (485 psi) and the NPS 30 Don Valley up to 3103 kPa (450 psi). If maintenance was required on this pipeline, or if a damage occurred, the system would be at risk from the reduced capacity on this singular path. Current limitations on its ability to move gas from west to east or east to west, in conjunction with a supply restriction at either Parkway or Victoria Square Gate Stations could result in customer outages, which will be further described in the *Limitations on Upstream Supply* section below.

25. Gas Control Operations rely on the NPS 26 line for daily load balancing purposes under normal operating conditions. Daily load balancing refers to Gas Control's ability to accurately forecast demand and schedule supply such that any resulting imbalance at the end of the Gas Day is maintained within 2% in order to avoid financial penalties imposed by upstream pipelines. Gas Control has access to select transportation services (i.e., STS and firm short notice services) at Parkway and Victoria Square Gate Stations that offer greater access to scheduling windows to balance demand at the end of the Gas Day. The NPS 26 plays a critical role in

allowing Gas Control to swing supply from west to east and vice versa depending on demand and supply availability. In addition, Gas Control is also required to manage hourly demand within reasonable tolerances to contractual limits. The connectivity offered by the NPS 26 between the XHP systems at either end of the GTA allows the Company to manage hourly peaks. Pressure restrictions on this line would limit Gas Control's ability to manage its upstream portfolio within contract parameters.

26. As noted above, flexibility provides the ability to respond to changed conditions. When possible, maintenance and integrity activities are undertaken during periods of low demand, when there is greater reserve capacity. Planned maintenance activities usually extend from April to November, however, it may also be required in periods of higher demand. These activities include pressure/flow reductions for welding, tie-ins, or leak or damage repairs; to mitigate the risk of damage when construction or maintenance is executed in the immediate vicinity of the pipeline; or, to carry out integrity inspection activities. Temporary reductions can be required for an extended period of time based on results from the integrity management program or from an engineering assessment, ending only after the underlying condition identified can be safely remediated. In some instances, the duration may extend over the entire winter. In 2012, over 20 integrity inspections were performed across the Enbridge franchise. As per Company policies, governing regulations and standards, immediate indications[15] must be mitigated within one week of the discovery. However, if immediate indications cannot be mitigated within the specified timeframes, other actions may be required. For example, among the pipelines inspected this year, systemic pipeline defects were discovered in two pipelines. As a result, these two pipelines are currently reduced to 80% of the normal operating pressure until an additional assessment can be completed in 2013.

[15] Immediate indications are pipeline features discovered through integrity inspections that must be mitigated within a specific time frame. Otherwise, operating pressures may be restricted for longer periods of time.

Unplanned events such as third party construction activities and pipeline damages pose additional challenges. Overall, the Company is faced with diminished flexibility to handle its current level of planned and unplanned annual maintenance and integrity activities.

27. Operational risk management at times requires the permanent lowering of pipeline operating pressures. Permanent de-rating of pipeline pressures may be required to mitigate operational risk due to integrity or engineering assessments; to adhere to code requirements as a result of changes in class location; to lessen the dependence on infrastructure encroached upon by urban development; or, to reduce the consequences of a third party damage. The Company maintains pipelines in accordance with governing regulations and standards and takes steps to manage operational risk. In the past, the Company has elected to de-rate pipelines to reduced pressures as a result of some of the above operational risk factors in previous applications to the Board. A summary of these pipelines is outlined in Table 2.

Table 2: Summary of Pipeline Pressure Reductions Ppreviously Discussed in Applications to the Board

Pipeline (Installation Year)	Pressure Reduction
NPS 20 HP Lake Shore pipeline (1954)	2760 to 1200 kPa
NPS 20 HP Winston Churchill pipeline (1958)	3350 to 1200 kPa
NPS 30 XHP pipeline (1963-1967)	2340 to 1900 kPa

28. Proper operational risk management requires that risks are minimized and/or eliminated where they can be, and that is a goal of the Company. High stress pipelines have differing risk characteristics than lower stress pipelines. Categorization of pipelines by stress level is common; a brief description of the method used follows.

29. "Yield stress" is a material property and is the stress at which a material will permanently deform. The yield stress of steel used in a pipeline is commonly referred to as pipe grade, or Specified Minimum Yield Strength (SMYS). Typically, the dominant stress in pipeline operation is the "hoop stress". Hoop stress is produced by the internal pressure of a fluid (liquid or gas) with the pipe or component, any external hydrostatic pressure, or both, that acts in the circumferential direction. When hoop stress is calculated for a pipeline, it is often normalized as a ratio between the operating pressure and the designed strength of the pipeline. In pipeline operation, the ratio of "hoop stress" to SMYS is often used to evaluate operational risk. This ratio is often represented as a percentage, % SMYS.

30. In general, the specific reference to threshold 30% SMYS is important for three reasons. First, it is the generally accepted “leak-rupture boundary” in industry and in Canadian regulations and standards. This means that there is a general understanding that below 30% SMYS a pipeline defect is likely to result in a leak, whereas above 30% SMYS a pipeline defect is at risk of causing a pipeline rupture. Second, it is required by Ontario Regulation 223/01 that an Integrity Management Program be in place for all pipelines operating at or above 30% SMYS. Third, the Company’s in-service welding procedures requires pipelines to operate below 30% SMYS to perform any welding on the mains while in operation.

31. The Company meets or exceeds pipeline design, maintenance, and operational requirements in accordance with governing regulations and standards. It also reviews, evaluates, and adopts best practices from industry. An example of a best practice from industry is the increased wall thickness on larger diameter, higher stress pipelines. Pipelines installed four decades ago, such as the NPS 26 and the NPS 30 Don Valley line, have wall thicknesses of 7.9 mm. Pipelines installed two decades ago, the NPS 36 Parkway North and MSL lines, have a wall thickness of 9.2 mm. In 2008, the NPS 36 line installed to supply PEC was installed with a wall thickness of 15.9 mm.

32. The NPS 26 and NPS 30 Don Valley lines both operate above 30% SMYS, both have a wall thickness that is thinner than a pipeline that would be installed today, and both are critical to system operation given the supply consequences of an outage of these pipelines. These factors are summarized in Table 3. The Company’s ability to provide reliable service is at risk given the lack of diversity of the supply path in these two lines, the limited flexibility of other pipelines to back-feed the same geographic areas, and the unavailable capacity to reduce these lines to below 30% SMYS on a temporary or operational basis to mitigate operational risk

in normal operating conditions. The absence of diversity and flexibility in periods of higher demand increases the potential risk incurred by the Company as it may limit its ability to either respond in a timely manner or maintain reliable supply to customers. The choice between these two options is not considered to be reasonable when system reinforcement mitigates the risk with the existing infrastructure.

Table 3: XHP Pipeline Infrastructure Supplying the GTA

Pipeline	Year Installed	Wall Thickness	SMYS	Supply to GTA System
NPS 26 pipeline	1967-1971	7.9 mm	37%	N/A
NPS 30 Don Valley pipeline	1971	7.9 mm	36%	15-25%
NPS 36 Parkway North pipeline	1986–1992	9.2 mm	37%	30-35%
NPS 36 MSL pipeline	1992	9.2 mm	27%	20-25%

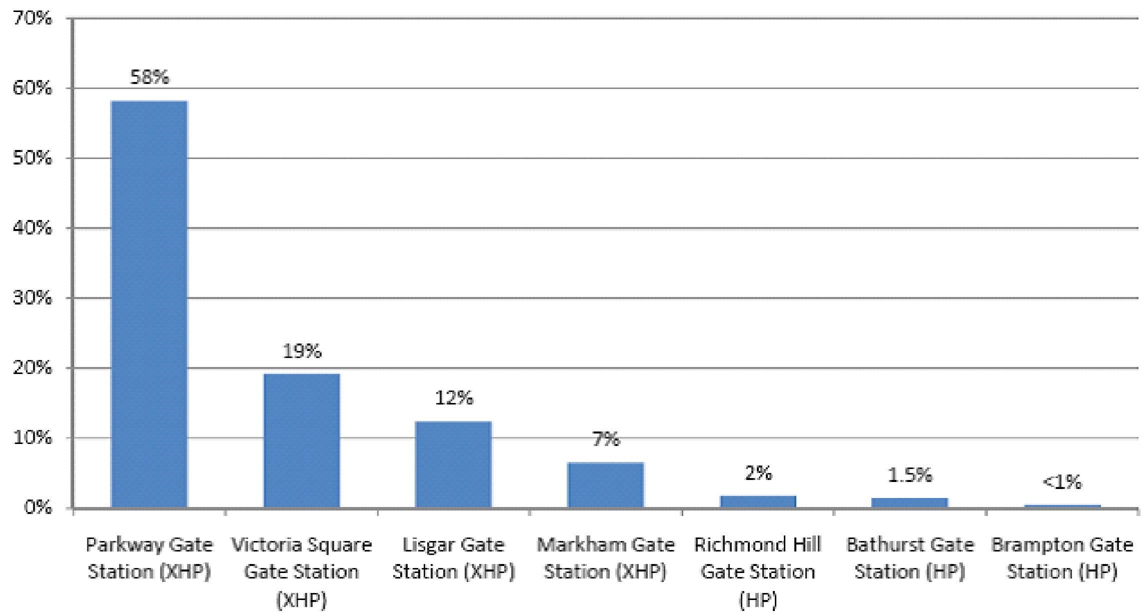
33. The Company believes that in order to ensure continued reliable and safe delivery of service, it should diversify the supply paths, increase the flexibility of the system, and reduce the operational risk associated with these two key pipelines by reducing the operating pressures below 30% SMYS. The Company plans to reduce the operating pressure of these two pipelines below 30% SMYS after the proposed facilities have been installed. It is expected that these lines would continue to be considered under the Company's Integrity Management Program.

Limitations with Entry Points into the Distribution System

34. The following section describes limitations with respect to diversity, flexibility and risk management for the entry points into the GTA system.

35. There are seven gate stations that provide natural gas supply to the broader GTA and surrounding area. Ostensibly, one might conclude that there is sufficient diversity in entry points in the GTA system. However these stations have a large variance in their capabilities. Four of the gate stations (Parkway, Victoria Square, Lisgar, and Markham) are connected into the XHP network and move 96% of the gas supply volumes from upstream transmission pipelines to downstream customers. Three of the gate stations (Brampton, Bathurst, and Richmond Hill) are connected into the HP network and move 4% of gas supply volumes. Figure 5 shows the percentage share of each gate station.

Figure 5[16]: Composition of Natural Gas Delivery through Gate Stations



36. Parkway, Victoria Square, and Lisgar Gate Stations – supply over 90% of the peak day demand flow. Parkway Gate Station currently supplies over half of the peak day requirements of the system, making Parkway a systemically important single facility for supply and system operation.

37. The Company considers the feed at Parkway, and the Parkway facility itself, as the single biggest risk in terms of consequences to system operations. Currently, the loss of the Parkway Gate Station during winter conditions would result in a

[16] The figure is based on un-normalized historical average deliveries on cold winter days from both TransCanada and Union Gas at gate stations supplying XHP or HP to the GTA Project Influence Area and surrounding area. The respective percentages are based on total station flows since an outage of a gate station may affect more than the Influence Area considered by this project.

~~37.~~ significant level of outages. System modeling of this event at a 35 DD indicates losses exceeding 270,000 customers plus PEC[17].

38. Large losses would occur because of the limited capability of both Lisgar, the oldest operating gate station, and Victoria Square, the second largest gate station in the GTA. Due to urban encroachment, Lisgar's capabilities have not been expanded over the decades. In fact, Lisgar typically only operates as a gate station in winter months. The XHP grid in the GTA currently has relatively weak linkages between Victoria Square and Parkway, particularly on cold winter days. The current system restriction is the NPS 26 pipeline, constructed in 1967, that connects the NPS 36 Parkway North pipeline with the NPS 30 Don Valley pipeline. The NPS 26 pipeline is not only smaller diameter, but also operates at a lower pressure than either of the two lines it connects. Consequently there is limited offset capability between the two largest stations in the GTA.

39. Due to the higher systemic risk of the Parkway Gate Station, the Company does not believe that it should expand the facility any further, and will therefore look to source any forecast growth in demand from another entry point into the system. The addition of a new gate station would be able to provide some level of backup to Parkway and allow better management of gas supply in planned and unplanned events on both the upstream and downstream sides of the station.

40. Enbridge has commissioned a benchmarking study to compare Parkway Gate Station with entry points supplying natural gas to other major metropolitan areas in the North Eastern U.S. with similar climates. The benchmarking study ~~is expected to be~~has been filed ~~with the Board early in 2013~~as Attachment 4. High supply /u

[17] As previously indicated, the gas demand from PEC is equivalent to the gas demand of 100,000 residential customers.

concentration at two gate stations and the inability to mitigate supply risk through flexibility in downstream distribution infrastructure points is currently a systemic risk. From a supply perspective, expansion of Parkway or the Victoria Square Gate Stations is not desirable and diversification of the entry of supply into the system is a necessary measure.

Limitations with Upstream Supply

41. Enbridge seeks to continually enhance its gas supply portfolio through diversity of supply basin and path, and through flexibility in its ability to respond to demand variations both intra-day and seasonally. Enbridge also assesses operational risk by monitoring trends in gas production and trading at supply basins and market hubs and by monitoring the quality of the transportation arrangements that bring supply to its franchise.

42. From a supply perspective, the Company is witnessing a significant decline in production and exports from Alberta and substantial growth in emerging supply basins in close proximity to the franchise. These trends are expected to accelerate over the medium term and are described in greater detail in Exhibit A, Tab 3, Schedule 5, but are summarized below. A report issued by the Alberta government projects a 75% decline in conventional gas available for export from Alberta by 2021. The resulting level of Alberta exports in 2021, if this prediction materializes, would be slightly greater than Enbridge’s current level of winter reliance on Alberta supply, leaving little supply for other shippers in Eastern Canada. While this report excludes prospects for Alberta and BC shale production from substantial known reserves, there is uncertainty around where this gas will ultimately flow (i.e., exports to Asia) and timing of development of these reserves.

43. At the same time shale gas production in the U.S. Northeast is projected to grow from approximately 1.8 PJ/d to 7.3 PJ/d between 2010 to 2021[18]. As of November 2012, approximately 0.4 PJ/d of Marcellus supply is flowing into Ontario. The increasing availability from emerging supply basins also provides the opportunity to procure gas supply more economically than western Canadian supply. However, infrastructure constraints east of Parkway and on Enbridge's distribution system limit access to such supply, resulting in higher cost supply and security of supply concerns.

44. Enbridge has also identified risks associated with the quality of both long haul and short haul transport required to meet winter demand. As identified at Table 2, Exhibit A, Tab 3, Schedule 5, the Company will require in excess of 500 TJ/d of Short Term Firm Transportation ("STFT") on the TransCanada Mainline in 2014, which is a less secure form of transport than Firm Transportation. In addition, approximately 300 TJ/d of supplies from direct purchase customers is not underpinned by known firm transportation arrangements. As a result, between 500 and 800 TJ/d of supply could arrive in the Enbridge franchise using "discretionary services" on the TransCanada Mainline. These services are either non-renewable, such as STFT or lower priority such as interruptible transport, and their availability is predicated on several factors. TransCanada is contemplating a reduction in its long haul capacity through conversion to oil and possible pressure de-rates on segments of its pipeline system as a result of changes to its integrity management program[19], which will affect the availability of discretionary transport relative to firm transport.

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[18] Based on data interpolated from the projections provided in the Energy Information Administration ("EIA") Annual Energy Outlook 2012. The Company would note that other projections of Marcellus supplies alone are higher than the total EIA shale supply projections for the U.S. Northeast by 2021.
[19] Source: Evidentiary record in NEB proceeding in RH-3-2011

Replacement of these discretionary services with year round firm transport will result in less efficient use of long haul pipe due to the seasonal nature of demand.

45. The Company has a long history of using short haul transport services to meet seasonal demand due to the lower costs of using short haul pipe at low load factors. However, vulnerabilities have also been identified in short haul transport services that are used to bring gas to Parkway for compression and further transport on the TransCanada system, for redelivery into the Enbridge franchise. Enbridge utilizes STS and short haul Parkway to Enbridge Central Distribution Area (“CDA”) transport services amounting to approximately 450 TJ/d in the winter time. Union Gas has identified the absence of stand by compression at Parkway as a supply risk, consequently loss of compression at Parkway could result in a shortfall of approximately 900 TJ/d for shippers downstream of Parkway. If such a shortfall were to occur, Enbridge, as the single largest Local Distribution Company (“LDC”) shipping gas east of Parkway, would expect to take a significant portion of the shortfall.

46. Diligent operational risk management requires that the Company plan for and address unusual but realistic system events. The Company prepared a load shed plan to respond to an upstream curtailment of supply from either TransCanada or Union Gas, known as the “Enbridge Load Shed Report”. System modeling was performed to identify isolable zones to respond to an event of this nature. In situations where either Parkway Gate Station or Victoria Square Gate Station is affected by a 300 to 400 TJ/d upstream supply shortfall, it is projected that approximately 150,000 to 225,000 customer losses would occur at a 41 DD, respectively. This estimate assumes that PEC is not consuming gas.

47. The proposed GTA Project addresses the limitations identified above. Details on the proposed facilities, operation, and system benefits are described in Exhibit A, Tab 3, Schedule 6.

MARKET GROWTH

1. The customer additions forecast for the area supplied by the GTA Project (herein referred to as the "GTA Project Influence Area", or "Influence Area") indicates that capacity demands will continue to increase over the period from 2015 to 2025 due to an increased number of customers.

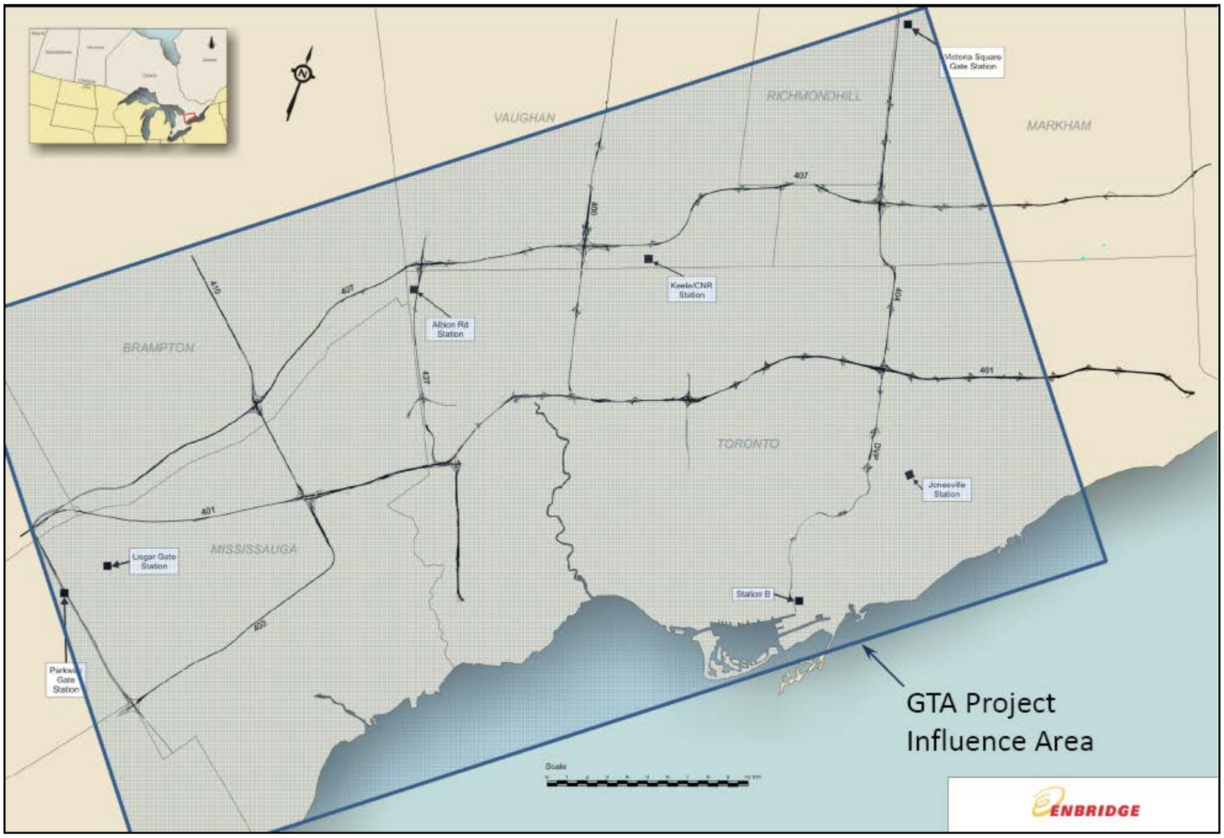
2. The customer additions forecast was developed using information sources and factors as follows:
   - Information from direct contacts with builders, developers, and municipalities regarding on-the-ground realities, such as the ongoing development projects;
   - Housing starts forecasts, as available from reliable third-party data sources;
   - Development projections, sourced from external consultants; and,
   - Economic factors, such as Gross Domestic Product ("GDP") growth, employment, and mortgage rates.

3. The forecast provides customer growth within the Influence Area for four customer sectors including residential, apartment, commercial, and industrial and covers the period from 2015 to 2025. The forecast is summarized below.

Influence Area

~~4.~~ A review of the distribution system was completed to determine the areas of the Enbridge distribution network where growth had a direct impact on the pressures at the current point of minimum system pressure, located at Station B. The municipalities identified within this area include Scarborough, North York, Toronto, Etobicoke, Brampton, Mississauga, Markham, Richmond Hill, and Vaughan. The GTA Project Influence Area is represented by the shaded portion in Figure 1 below.

Figure 1: Map of the GTA Project Influence Area



~~5~~4. For the purposes of network analysis, the GTA Project Influence Area was sub-divided into 152 smaller geographic areas upon which the customer growth was added to the network models. This allows more specific point loads to be added to the distribution system to better reflect where gas is consumed. This ultimately allows Enbridge to forecast the anticipated pressures at various points in the network and to optimize reinforcement options and ensure reliable delivery.

Customer Additions Forecast

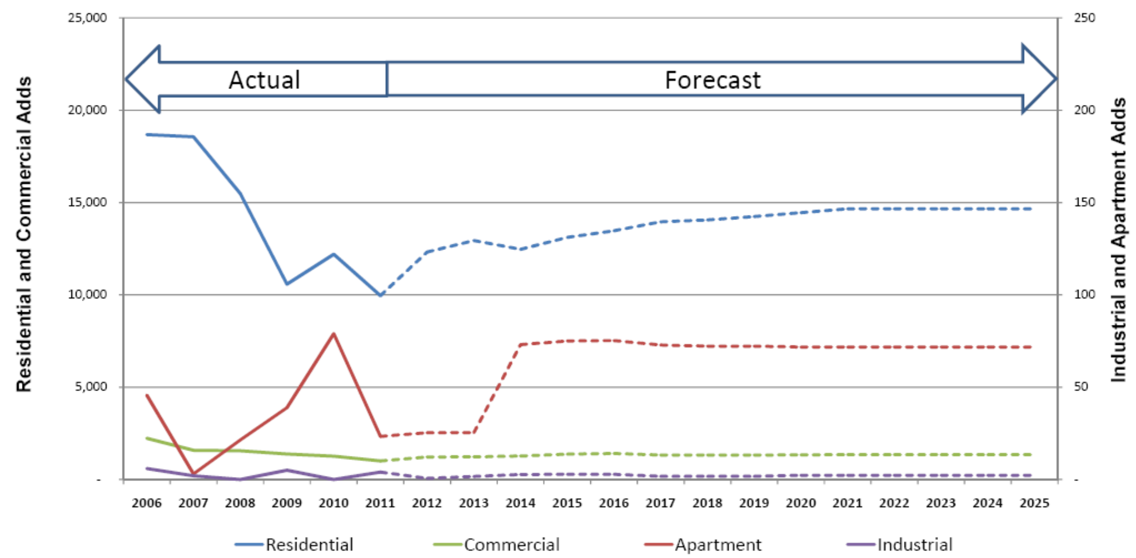
5. The customer additions forecast is summarized in Table 1. During the period from 2015 to 2025, ~~172,263~~161,423 total customers are projected to be added to the system /u

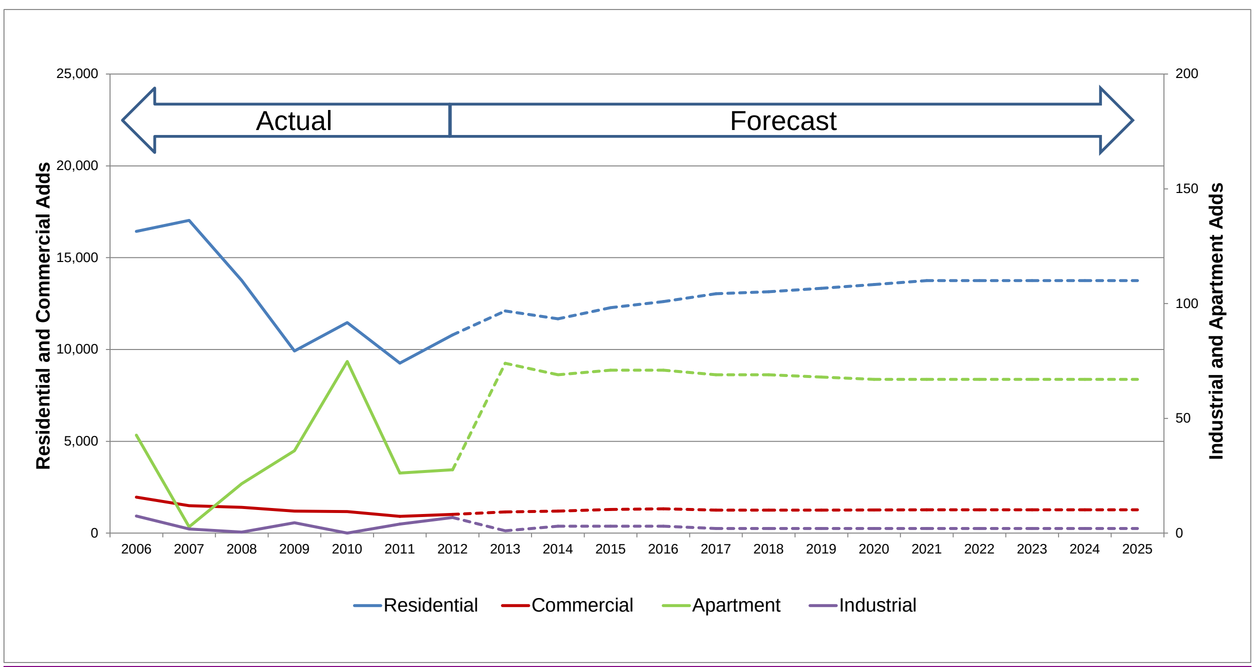
~~6.~~ supplied in the GTA Project Influence Area. The forecast is shown in conjunction with six years of historical customer additions (2006-2011) in Figure 2. Figure 2 also includes the forecast for 2012 to 2014; however, these three years are not included in the economics of this application.

Table 1: Incremental Customer Additions by Sector in the GTA Project Influence Area (2015 – 2025)

Year	Residential	Commercial	Apartment	Industrial	Total
2015	~~13,112~~12,277	1,~~370~~291	~~75~~71	3	~~14,560~~13,642
2016	~~13,471~~12,607	1,~~412~~327	~~75~~71	3	14,~~961~~008
2017	13,~~955~~034	1,~~328~~250	~~73~~69	2	~~15,358~~14,355
2018	~~14,062~~13,148	1,~~331~~253	~~72~~69	2	~~15,467~~14,472
2019	~~14,245~~13,331	1,~~328~~250	~~72~~68	2	~~15,647~~14,651
2020	~~14,448~~13,535	1,~~339~~261	~~71~~67	2	~~15,860~~14,865
2021	~~14,662~~13,748	1,~~347~~269	~~71~~67	2	~~16,082~~15,086
2022	~~14,662~~13,748	1,~~347~~269	~~71~~67	2	~~16,082~~15,086
2023	~~14,662~~13,748	1,~~347~~269	~~71~~67	2	~~16,082~~15,086
2024	~~14,662~~13,748	1,~~347~~269	~~71~~67	2	~~16,082~~15,086
2025	~~14,662~~13,748	1,~~347~~269	~~71~~67	2	~~16,082~~15,086
2015-2025	**~~156,603~~146,672**	**~~14,843~~13,977**	**~~793~~750**	**24**	**~~172,263~~161,423**

Figure 2[1]: Historical and forecast customer growth for the GTA Project Influence Area (by sector)





/u

[1] The residential and commercial attachments are on the left axis and the industrial and apartment attachments are scaled on the right axis.

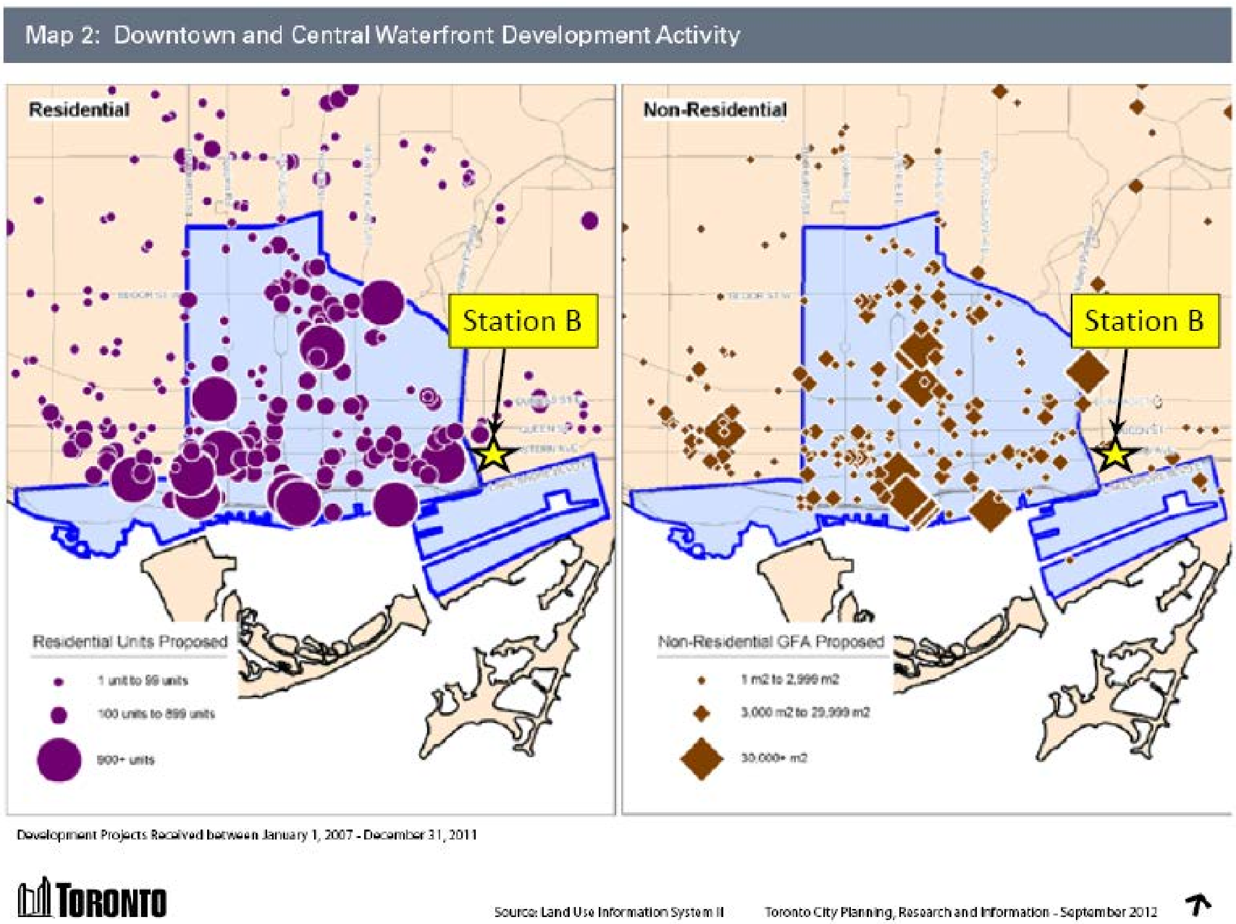
6. The residential sector constitutes the vast majority of total customer additions and follows the trends in housing starts. Housing starts are driven by various factors including GDP growth, employment, immigration, and mortgage rate expectations. Consensus forecasts for Ontario were used to project the underlying economic trends. The global recession in 2008 and 2009 caused a sharp drop in residential customer additions followed by a gradual recovery. Housing starts are expected to remain buoyed by the steady pace of employment and economic growth in Ontario. However, housing formation is expected to moderate as demographics shift. While the GTA will continue to experience strong population growth, mostly from immigration, labour-force growth will be slower as a significant portion of the working age population will retire. As a result, the demand for new housing will flatten out in

~~7.~~ the longer term. Relatively positive economic trends in the forecast period will continue to attract investments in the commercial and industrial sectors in the long term although at a slower pace.

~~8.~~7. A recent bulletin, issued by the City of Toronto in October 2012, summarizes information from the City Planning Division on residential and non-residential growth. The bulletin notes that the downtown and waterfront areas are forecast to experience the strongest residential and non-residential growth at 45% and 31%, respectively[2], of the total growth in the city. Figure 3 represents this growth in the downtown and waterfront areas in Toronto. Residential growth (residential, apartment) is represented on the left and non-residential growth (mainly commercial) is represented on the right. This figure is intended to demonstrate the growth in the area, which is in close proximity and directly fed from Station B, the location of minimum system pressures.

[2] This is based on development proposals received by the City of Toronto between January 1, 2007 and December 31, 2011, but not yet built. Information was retrieved from “Profile Toronto”, October 2012 Issue.

Figure 3[3]: Development projects received by the City of Toronto
(2007 to 2011, yet to be built)



Load Growth

~~9.~~8. Pipelines and facilities are sized based on the forecasted total peak hourly consumption, which is calculated from the customer additions forecast and the peak hourly consumption estimate. For each municipality identified in the Influence Area, the peak hourly consumption estimate was calculated for each customer type based

[3] "Profile Toronto", October 2012 Issue. The location of Station B is overlaid on the figure.

on the five years of historical peak hour consumption. The data was regressed with temperature information to determine peak hourly gas consumption at a 41 DD. A reduction factor was then applied to account for efficiency gains through Demand Side Management ("DSM") and customer losses through building demolition. Large volume customers, such as power plants, are evaluated on an individual basis to determine replacement capacity requirements and therefore excluded from the customer additions forecast. The calculated peak hourly consumption value for each customer sector for each municipality was applied to customer additions forecast.

~~10.~~9. The total forecast peak day demand, shown in Table 3, is the incremental load growth plus the load required by the existing customer base. Gas demand and supply is further described in Exhibit A, Tab 3, Schedule 5.

Table 3: Total forecast peak day demand for the Project Area (2015 to 2025)

Year	Peak Day Demand	
	10^3 m^3/hour	TJ/day
2015	3093	2443
2016	3117	2462
2017	3141	2480
2018	3165	2499
2019	3189	2518
2020	3213	2536
2021	3237	2555
2022	3261	2574
2023	3285	2593
2024	3309	2612
2025	3333	2631

NATURAL GAS DEMAND, SUPPLY & EXPECTED GAS SUPPLY BENEFITS

Note: Elements of this evidence have been updated through the submission of Exhibit A, Tab 3, Schedule 9 (filed on July 22, 2013).

1. The purpose of this evidence is to provide an explanation of gas demand and supply trends along with an estimate of the gas supply benefits Enbridge ~~Gas Distribution Inc. ("Enbridge" or the "Company")~~ expects to generate through gas supply portfolio changes once the GTA Project facilities are put into service.

~~1.~~

2. Exhibit A, Tab 3, Schedule 2 describes the evolution of distribution system facilities within the GTA Project Influence Area. The XHP distribution system serving this Influence Area has not had a major expansion and enhancement since 1992. Consequently, where possible, the 1992 to present period is used when discussing the trends in demand and supply provided in this evidence.

~~2.~~

Gas Demand

3. Demand for natural gas within the franchise area served by the Company is influenced by several variables. Weather, economic conditions, customer additions, total customers, customer mix, energy conservation and Demand Side Management ("DSM") programs and natural gas prices are all variables which can influence the demand for natural gas. For example, low gas prices combined with customer additions and colder temperatures, all else equal, can be expected to increase the demand for natural gas. Conversely high gas prices, increased energy conservation and DSM programs, and slow economic growth, all else equal, can be expected to decrease demand for natural gas. These variables can also work against each other creating a net impact on natural gas demand.

~~3.~~

4. In addition these variables can impact the shape of the demand profile throughout any given year or during any given day. For example, increases in the number of temperature sensitive customers can be expected, all else equal, to increase natural gas demand during the heating season and at peak or near-peak weather conditions. Increases in the number of temperature insensitive customers will not only increase demand during peak and near-peak conditions but also during off-peak periods as well.

5. Over time changes and trends in these variables will impact the total amount of natural gas demand each year as well as the shape of the demand profile within any particular year or day.

Trends in Annual Demand[1]

6. Since 1992 annual gas demand in the Central Weather Zone has increased. However, trends in annual demand differ from sector to sector. The apartment, commercial, and residential sectors have, on average, experienced increased demand for natural gas whereas the industrial sector has, on average, experienced a decline in demand for natural gas. Figure 1 on the following page shows total annual demand, by sector, by year for the Central Weather Zone[2].

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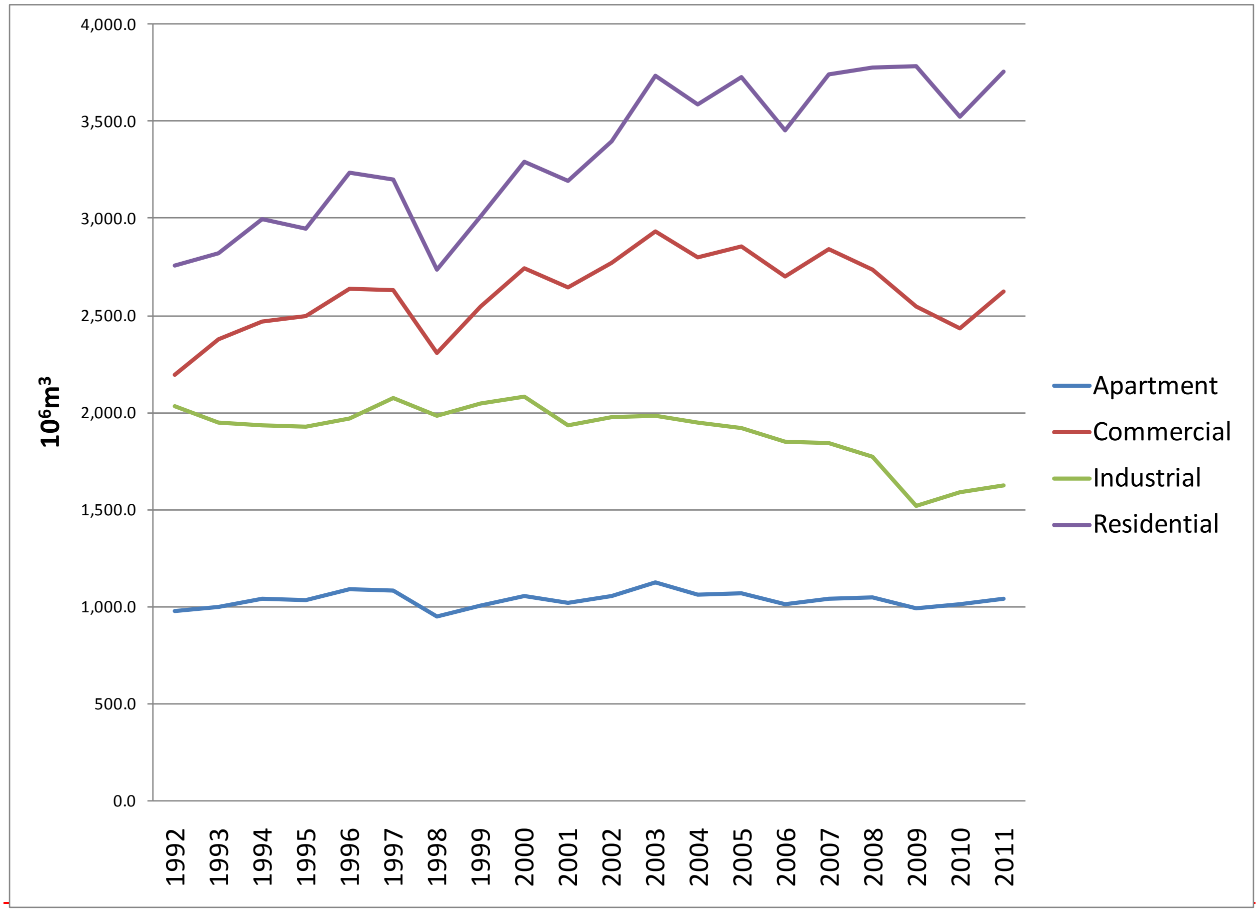
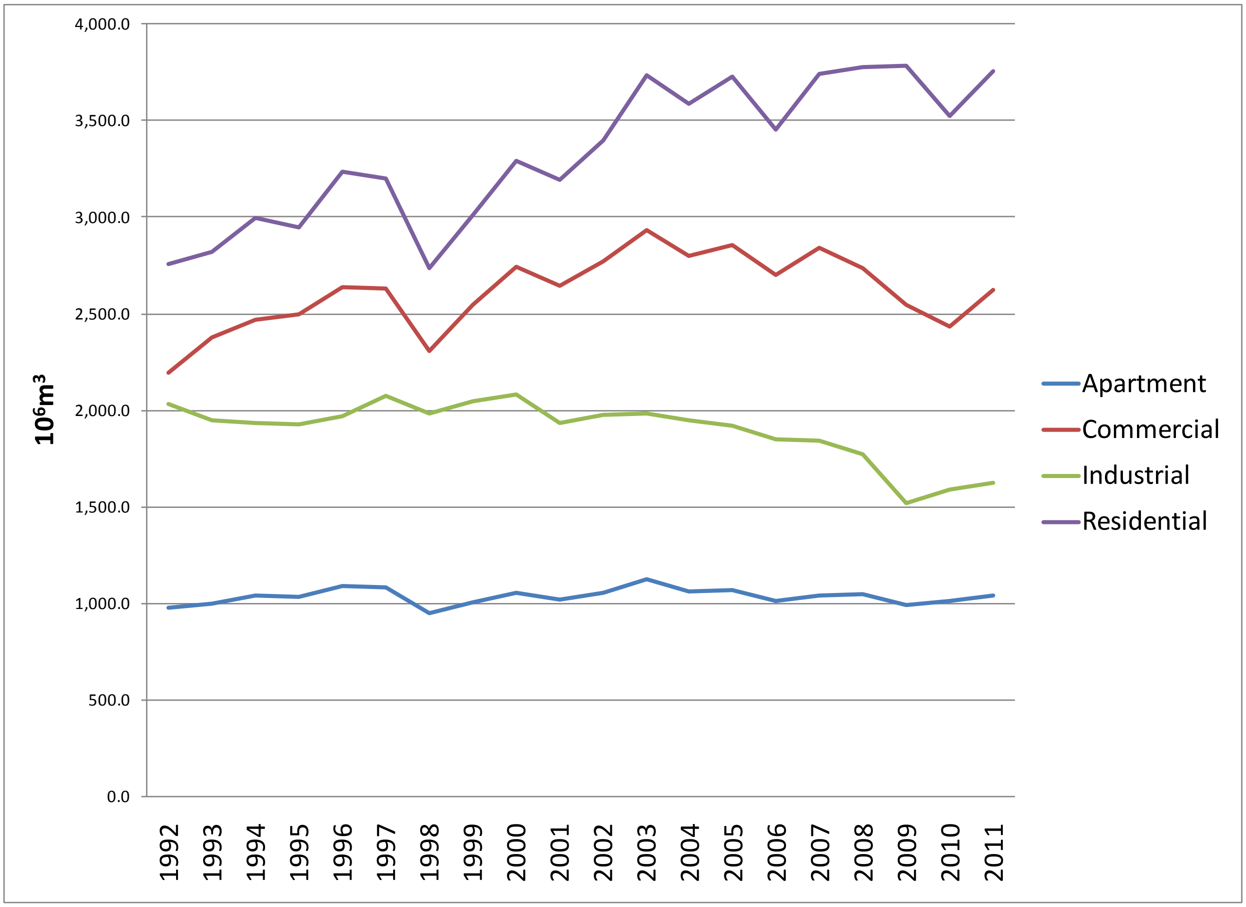
[1] Annual demand trends by sector are discussed using billing system data since daily ~~sendout~~send out volumes cannot be attributed to any particular sector. Data are presented for the Central Weather Zone as illustrative of the trends that have been experienced within the GTA Project Influence Area. The Central Weather Zone is comprised of the Metro, Western, Central and Northern areas of the Enbridge franchise area. The Enbridge CDA is also referenced in this evidence. The Enbridge CDA is comprised of the Central Weather Zone and the Niagara Weather Zone.

[2] Data presented in Figure 1 are un-normalized volumes.

Figure 1: Natural Gas Demand – Central Weather Zone





7. Temperature sensitive residential demand has increased from 35% of total demand in 1992 to 42% of total demand in 2011 for the Central Weather Zone. Industrial demand as a percentage of total demand on the other hand has declined. In 1992 industrial demand comprised 26% of total demand for the Central Weather Zone. In 2011 this figure declined to 18% for the Central Weather Zone. These trends in annual demand are largely a result of customer additions and changes in customer mix over time in addition to macroeconomic factors.

8. Table 1 below provides the number of customers, as measured by unlocked customers, for the Central Weather Zone for the years 1992 and 2011.

Table 1: Unlocked Customers by Sector, Central Weather Zone

(000's)	Apartment	Commercial	Industrial	Residential	Total
1992	4.6	83.6	7.0	753.8	849.0
2011	5.6	114.3	5.9	1,378.4	1,504.1

(000's)	Apartment	Commercial	Industrial	Residential	Total
1992	4.6	83.6	7.0	753.8	849.0
2011	5.6	114.3	5.9	1,378.4	1,504.1

9. In 1992, temperature sensitive residential customers comprised approximately 89% of the total customer stock in the Central Weather Zone. By 2011 this percentage had increased to approximately 92%. The number of industrial customers has declined, primarily as a result of economic factors.

10. The trends observed in apartment, commercial, and residential customer growth are largely a result of extended periods of economic growth and more recently a favourable housing market and interest rate environment. The continual addition of customers in these three sectors has increased natural gas demand. Growth in demand for these sectors has been partially offset by energy conservation and the Company's DSM programs.

11. The trends in industrial customer ~~growth~~sector are due in part to an appreciation of the Canadian dollar, natural gas price volatility experienced in the early 2000's, a general shift from domestic production to production overseas, a shift towards a more service oriented economy in Ontario, and more recently slow economic growth. Loss of industrial customers has in part lead to a decline in natural gas

demand for this particular sector.

12. Temperature sensitive customer demands are seasonal during the year whereas industrial customer demands are relatively flat (i.e., base load) throughout the year. The implications of these demand trends on natural gas supply and the Company's gas supply portfolio are more fully discussed in the sections that follow.

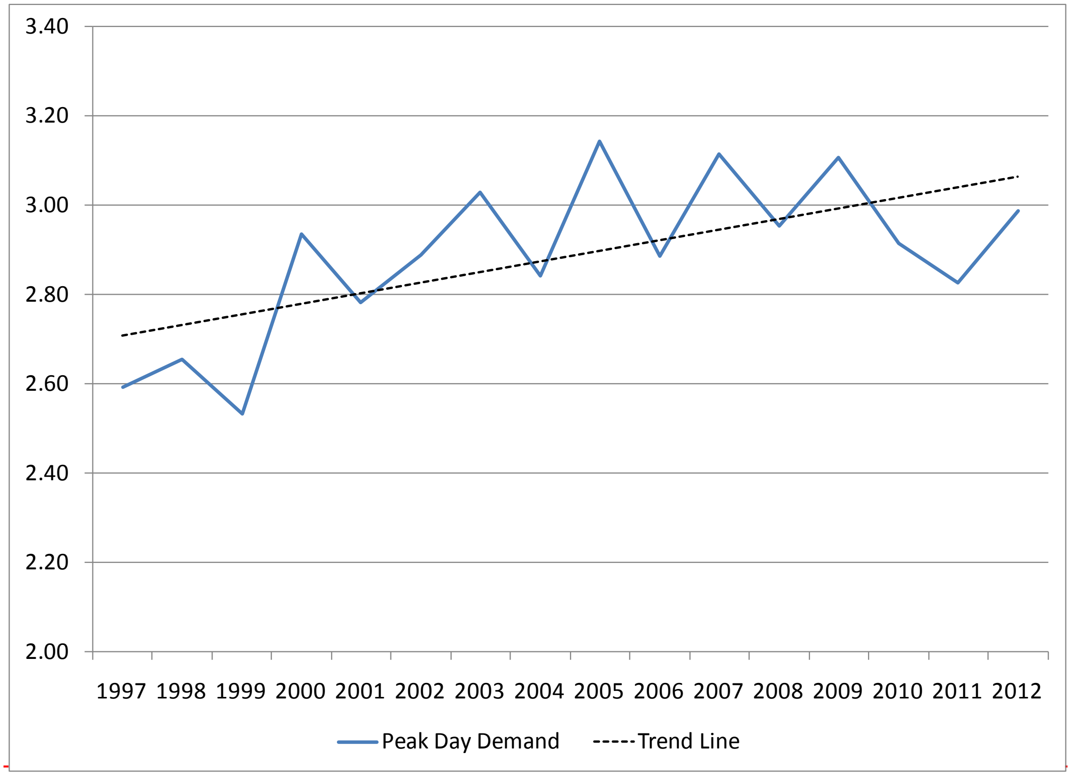
Peak Day Demand Trends

13. Enbridge has an obligation to serve its customers and meet their demands for natural gas in a safe, reliable, and cost effective manner. Enbridge constantly evaluates its gas supply portfolio to ensure this is the case. Ensuring that the gas supply portfolio is able to meet demand on the crucial peak day, or day of highest demand, is extremely important. In light of the demand trends discussed above and changes in the natural gas market it is reasonable to expect that the composition of the gas supply portfolio utilized by the Company to meet natural gas demand has changed. Over time the Company has reduced distance of haul in order to serve an increasingly temperature sensitive demand profile. The reduction in distance of haul has also been driven by diversity and economic considerations.

14. Figure 2 and Figure 3 on the following pages show normalized peak day demand for the Central Weather Zone and the GTA Project Influence Area[3].

[3] Peak day demand is normalized to a Design Criteria of 41.4 DDs for Figure 2 and 41 DDs for Figure 3. 41.4 DDs are used for gas supply planning purposes for the Central Weather Zone whereas 41 DDs are used by System Analysis & Design when planning distribution facilities for the areas within the GTA Project Influence Area.

Figure 2: -Normalized Peak Day Demand – Central Weather Zone (PJs)



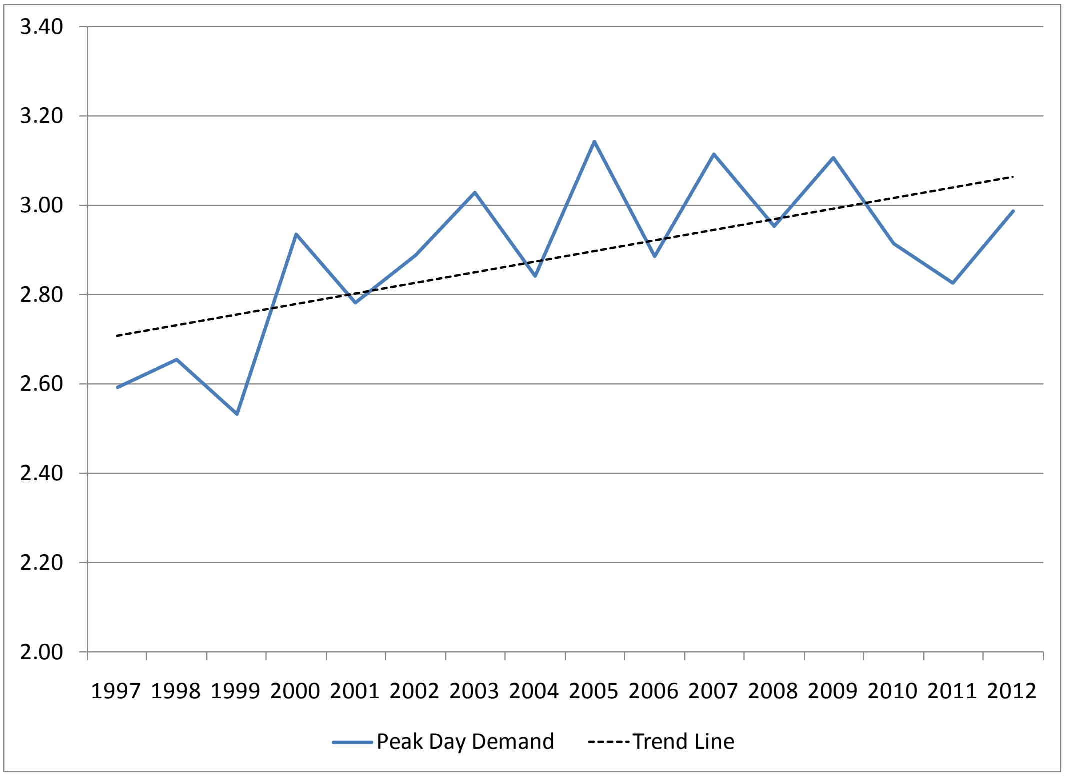
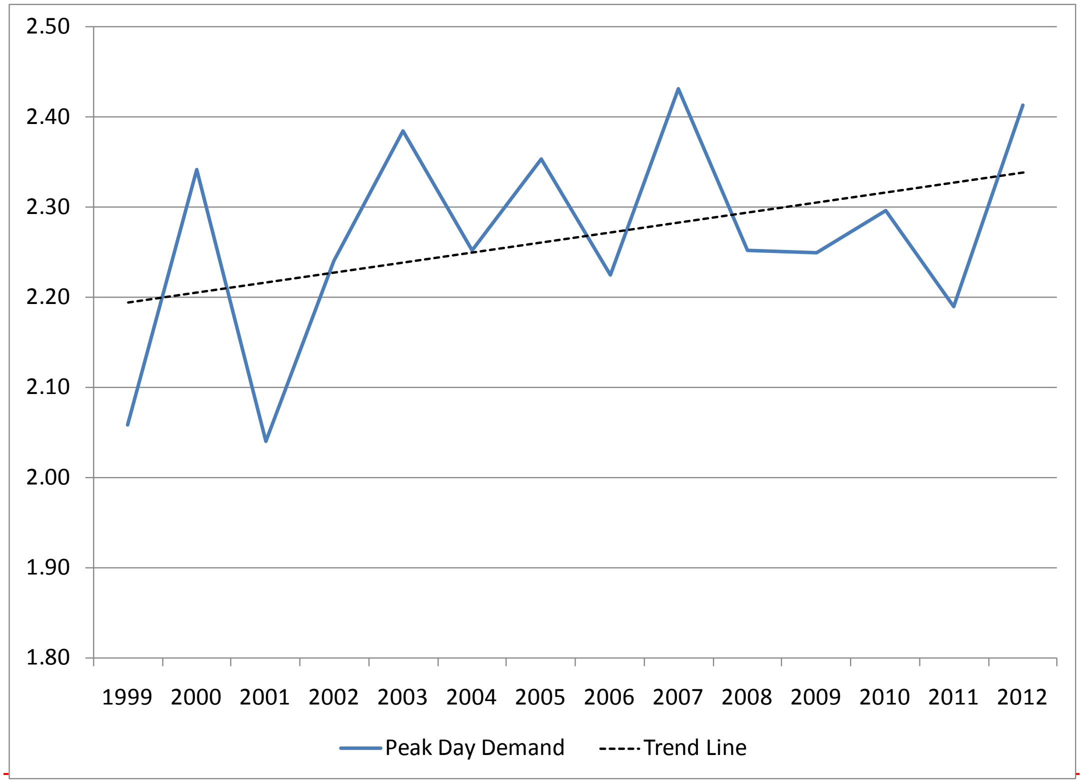
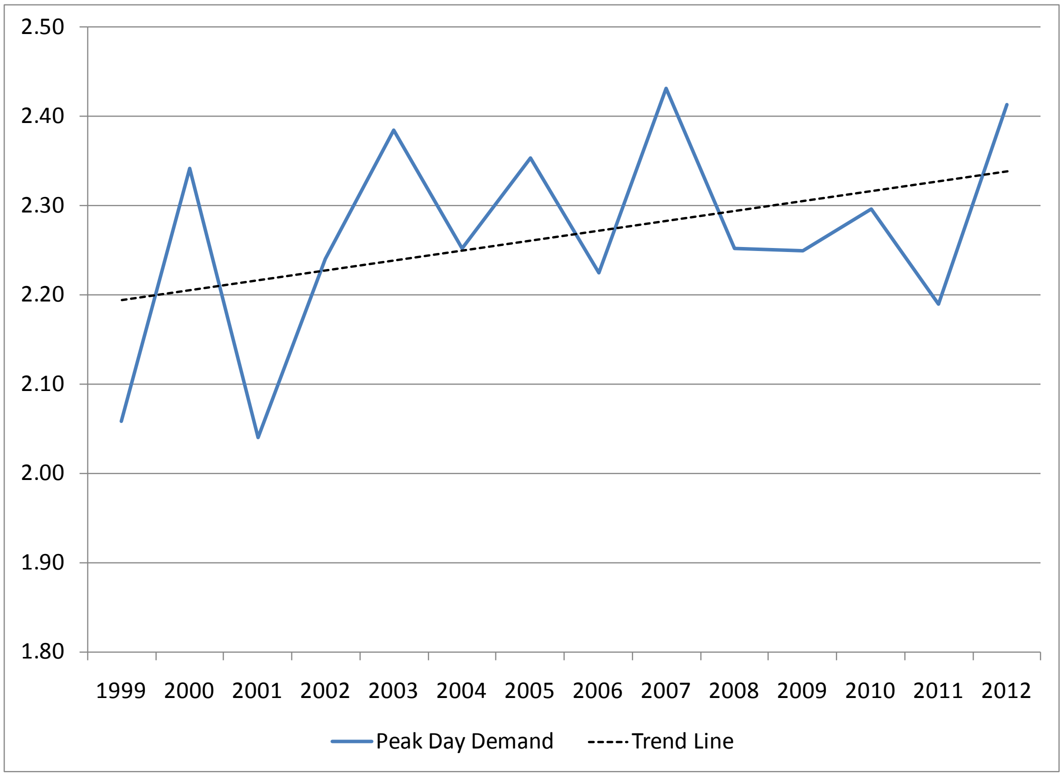

3.40
3.20
3.00
2.80
2.60
2.40
2.20
2.00
1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012
Peak Day Demand
Trend Line

Figure 3: -Normalized Peak Day Demand – GTA Project Influence Area (PJs)



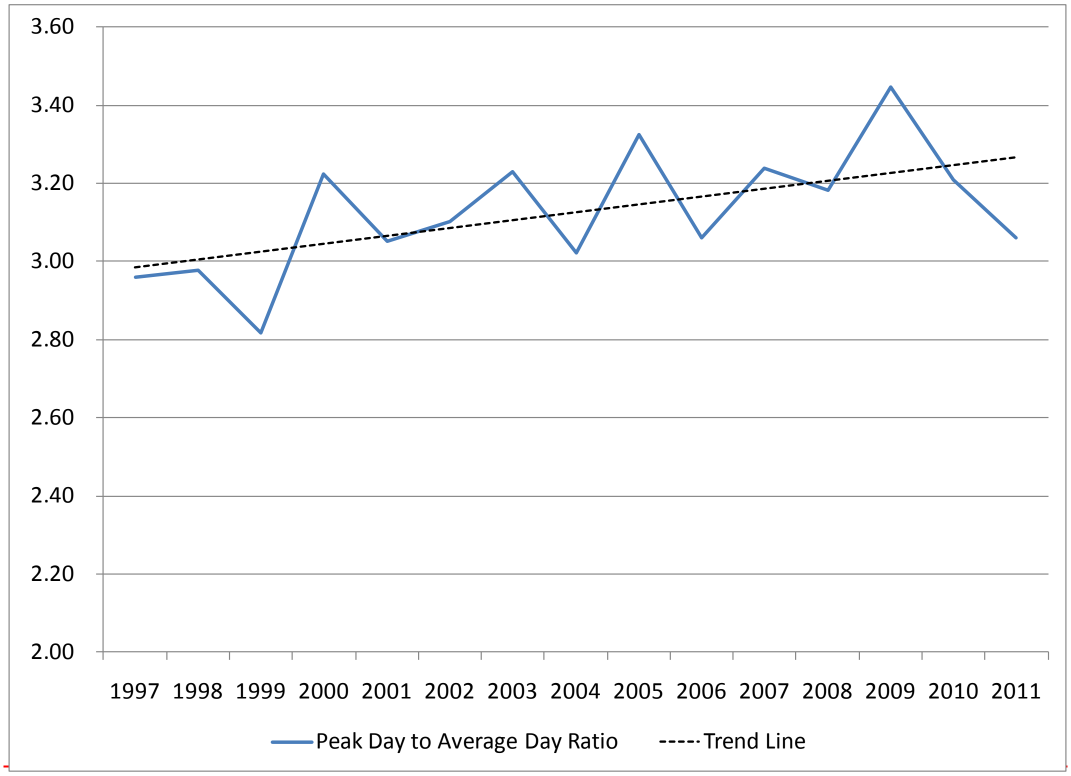


15. On average peak day demand for the Central Weather Zone has increased by 1.2% per year since 1997. The comparable figure for the GTA Project Influence Area is 1.5% per year since 1999.

16. Figure 4 and Figure 5 on the following pages show the ratio of normalized peak day demand to average day demand for the Central Weather Zone and the GTA Project Influence Area[4].

[4] Data in Figure 4 and Figure 5 have been normalized to the same Design Criteria used to normalize the data in Figure 2 and Figure 3.

Figure 4: Ratio of Peak Day Demand to Average Day Demand – Central Weather Zone



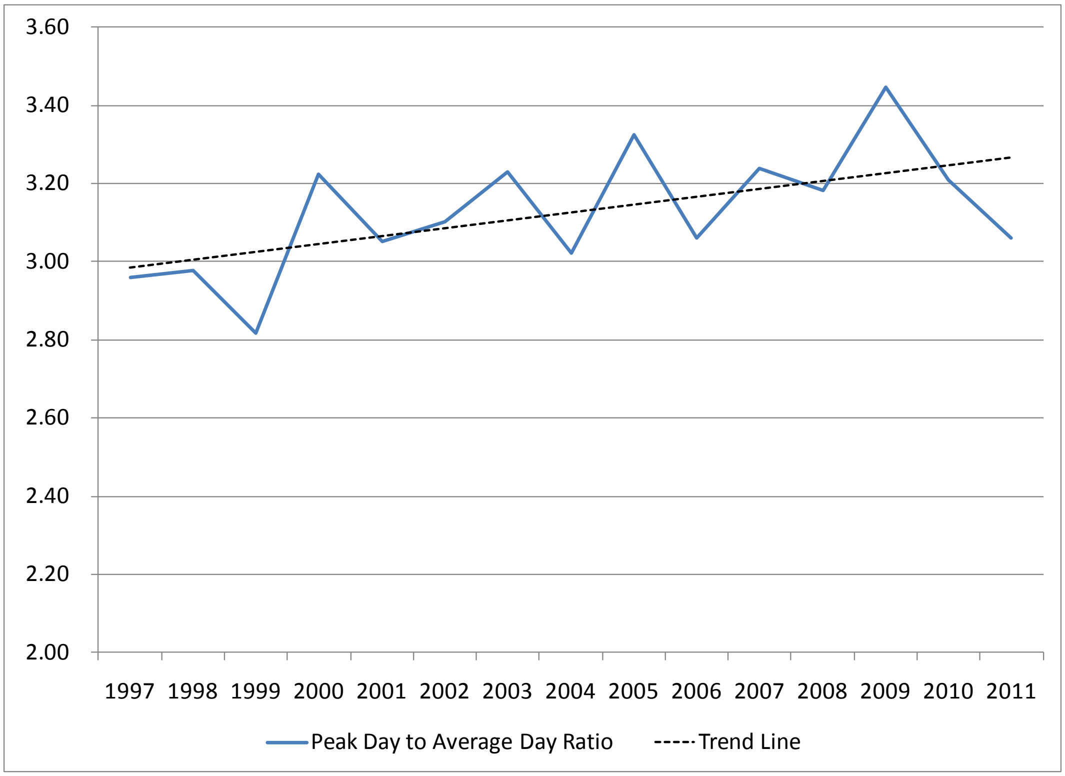
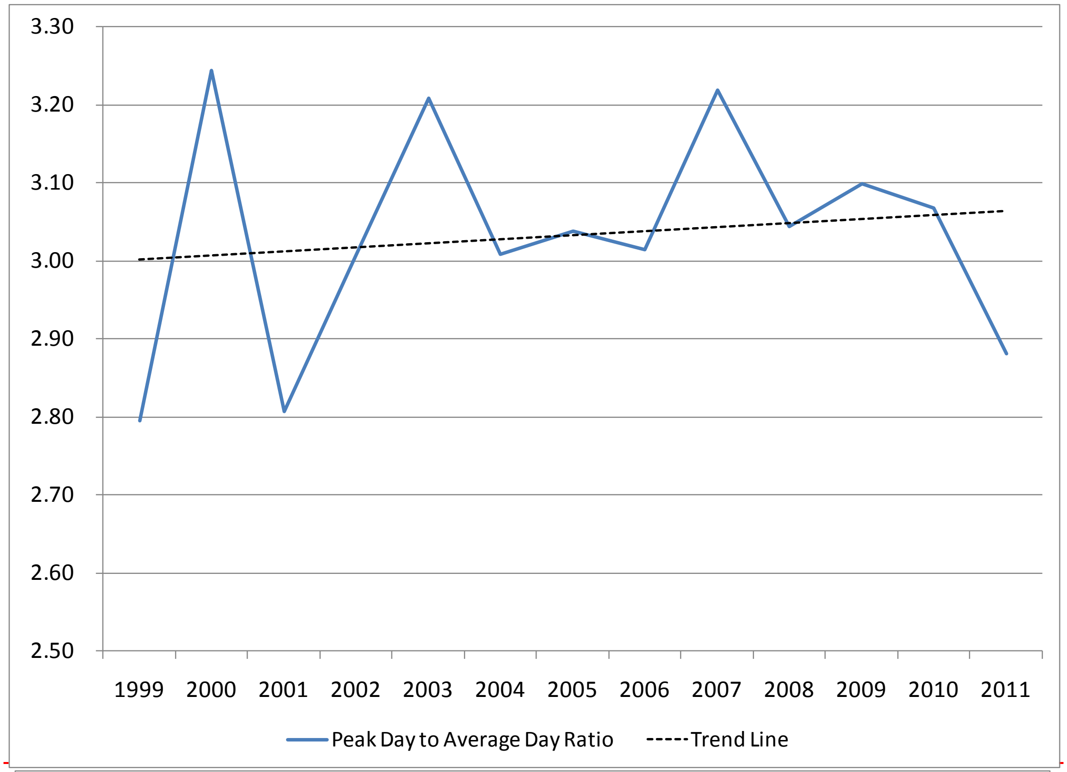

3.60
3.40
3.20
3.00
2.80
2.60
2.40
2.20
2.00
1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011
Peak Day to Average Day Ratio
Trend Line

Figure 5: Ratio of Peak Day Demand to Average Day Demand –
GTA Project Influence Area


3.30
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2.90
2.80
2.70
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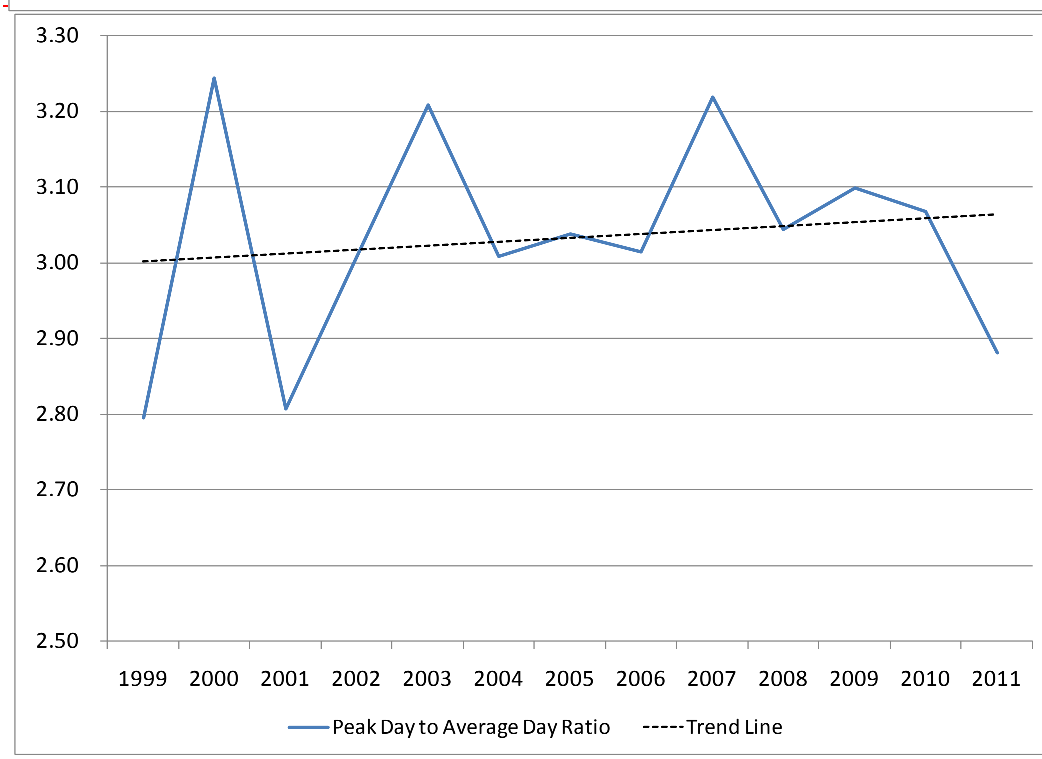
2010
2011
Peak Day to Average Day Ratio
Trend Line


3.30
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Peak Day to Average Day Ratio
Trend Line

17. The ratio of peak day demand to average day demand for the Central Weather Zone and the GTA Project Influence Area show an increasing trend over time indicating the distribution system load factor has tended to decline over time.

~~17.~~

18. The trend of increases in peak day demand is a result of the demand trends discussed above. While industrial demand has declined, the continued addition of temperature sensitive customers to the distribution system has, on average, increased peak day demand over time. Likewise, the increase in the ratio of peak day demand to average day demand is largely a result of changes in the mix of customers with the majority of customer additions being temperature sensitive residential customers. Residential customer additions and the loss of industrial customers have caused the demand load profile to become “peakier” as a result of greater seasonal and peak day demand relative to average day and baseload demand.

Gas Supply

19. The current gas supply portfolio reflects, in part, the implications of the demand trends discussed above and changes resulting from the evolution of the market for natural gas.

20. As the demand profile has become more seasonal and baseload demand has declined the Company has adjusted its supply portfolio by increasing the amount of short haul contracts to meet seasonal and peak day demand, reducing reliance on

paths of longer haul. Table 2 on the following page compares the peak day supply and demand balance for the 2002 Test Year and the current estimate for 2014[5].

[5] The 2002 supply/demand balance in Table 2 is derived based on projected peak day demand for the test year assuming transportation contracts in place as of November 1, 2001.

Table 2: -Peak Day Supply/Demand Balances for 2002-& 2014 (TJ/d)

	2002	2014
Peak Day Demand Forecast	3,548	3,950
Curtailment	177	163
Peaking Supplies	311	158
TCPL		
STFT	0	519
Long Haul	475	243
Short Haul	0	347
STS	317	365
Union	1,707	1,775
Other Supply	34	33
Direct Purchase		
Delivered Supply	112	288
Delivered Via Assignment From EGD	414	60

	2002	2014
Peak Day Demand Forecast	3,548	3,950
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TCPL		
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Short Haul	0	347
STS	317	365
Union	1,707	1,775
Other Supply	34	33
Direct Purchase		
Delivered Supply	112	288
Delivered Via Assignment From EGD	414	60

21. The Company has reduced reliance on curtailment due to a reduction in the number of customers choosing an interruptible rate thereby reducing the amount of

volumes available for curtailment.

22. Reliance on peaking supplies has declined due to reliability concerns relating to this service. The Company continues to be concerned about the reliability of peaking supplies due to a recent failure to deliver in 2011.

23. In addition to the factors noted above, Direct Purchase ("DP") supplies have declined overall as customers have migrated back to system gas supply. Delivered supplies from DP customers have increased whereas DP supplies underpinned by assignments of transportation capacity from the Company have declined.

24. Contracted ~~TransCanada firm~~TransCanadafirm long haul capacity has declined as a result of DP turnback and the relative economics of supplies sourced from the ~~WCSB.~~Western Canadian Sedimentary Basin ("WCSB"). Firm short haul capacity has increased as a result of diversification away from Western Canadian supplies, the economics of supplies from Chicago and the Dawn Hub, and the shift to a more seasonal demand profile.

25. More recently the Company has contracted for Short Term Firm Transportation ("STFT") service on the TransCanada Mainline ("Mainline") to meet seasonal and peak day demands. The Company expects to continue to do so absent the GTA Project. This service is firm and contract terms for STFT can vary which makes it an appropriate substitute for peaking supplies. STFT is a less expensive option relative to annual long haul capacity on the Mainline.

26. However, STFT is a discretionary service which does not have renewal rights. In addition, it is priced off of the firm transportation toll for the same path.

Consequently, the economics of STFT are determined, in part, by tolls on the Mainline. Recent increases in TransCanada tolls have increased the cost of this service relative to prior years. Holding peaking supplies and curtailment constant, increasing reliance on STFT in the future will likely result in lower load factors on incremental amounts of this capacity as the Company believes three months is the minimum contract term appropriate for this service.

27. TransCanada recently indicated that it would not be continuing integrity work on certain Mainline assets for the remainder of 2012 and that it is currently evaluating the possibility of converting certain Mainline assets to oil service. Both of these events, if continued in the case of the former, or if completed in the case of the latter, will potentially limit the amount of capacity available for provision of discretionary services on the TransCanada Mainline system, such as STFT, in the future.

North American Supply Expectations

28. Supply dynamics in North America are undergoing a period of significant change. Over time shifts to paths of shorter haul have impacted flows to Ontario markets and the points at which supplies are procured. More recently, the development of emerging supply basins in close proximity to the Ontario market, such as the Marcellus and Utica, have continued to alter the supply and flow picture across North America. As of November 1 of this year natural gas is now flowing into Ontario at Niagara, traditionally an export point for Canadian natural gas for the past few decades.

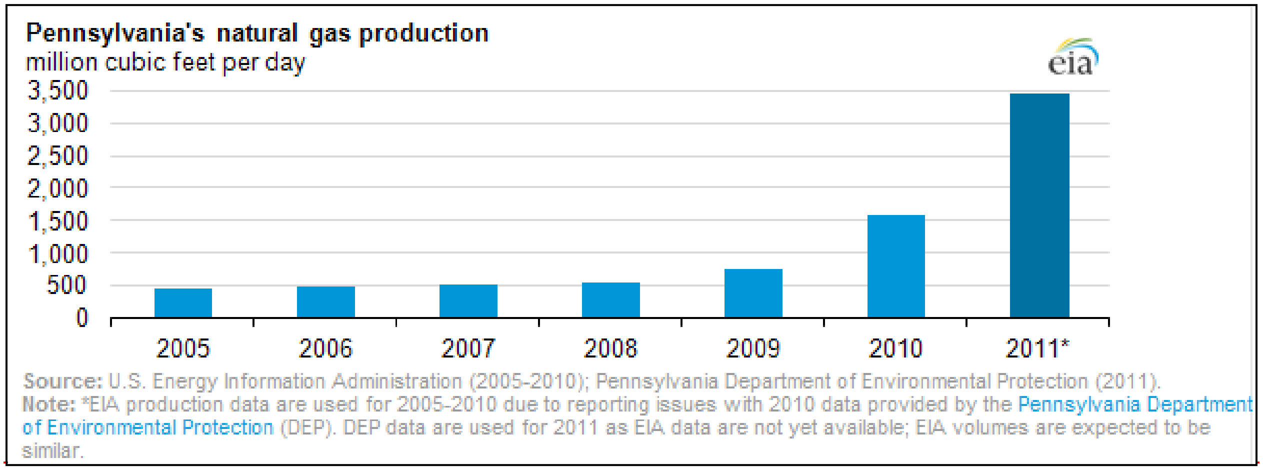
29. Through recent facilities upgrades by Tennessee Gas Pipeline ("TGP"), National Fuel Gas Supply Corp. ("NFG") and TransCanada gas produced from the Marcellus formation can now be transported north to the US/Canada ~~boarder~~border to an interconnect with TransCanada and onwards to the Ontario market. Marcellus producers such as Statoil, Anadarko, Mitsui, and Seneca Resources have contracted long term for capacity on the TGP and NFG transmission systems to bring gas produced from Marcellus to eastern Canadian markets.

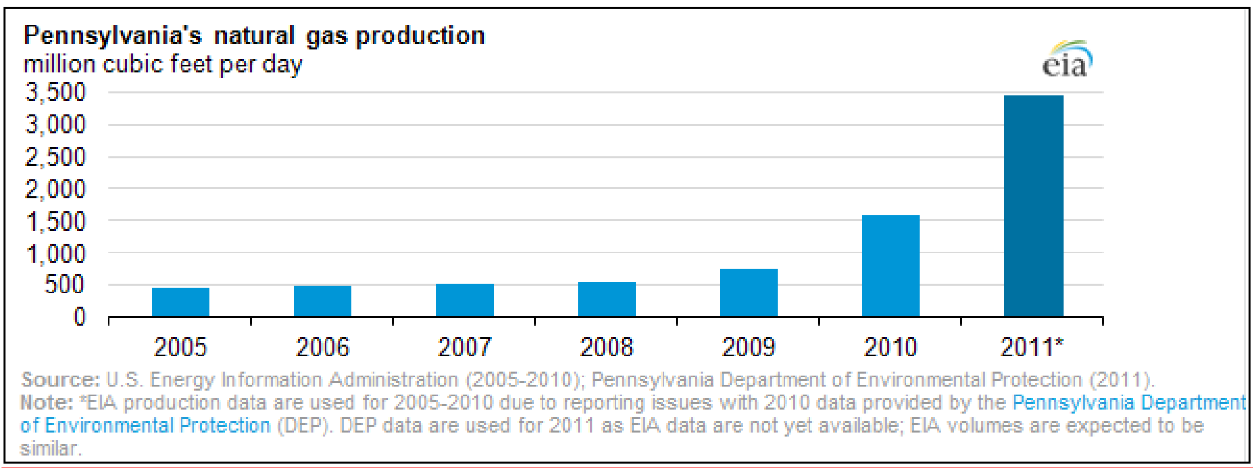
30. The Marcellus and Utica shale basins are poised for significant growth in the coming years. The state of Pennsylvania, through which the Marcellus and Utica run, experienced an almost four fold increase in natural gas production during the 2009 to 2011 timeframe. Figure 6 on the following page shows a chart provided in

a recent Energy Information Administration ("EIA") publication containing natural gas production statistics for Pennsylvania[6].

[6] Energy Information Administration, Today in Energy, "Horizontal drilling boosts Pennsylvania's natural gas production", May 23, 2012.

Figure 6: Pennsylvania's Natural Gas Production



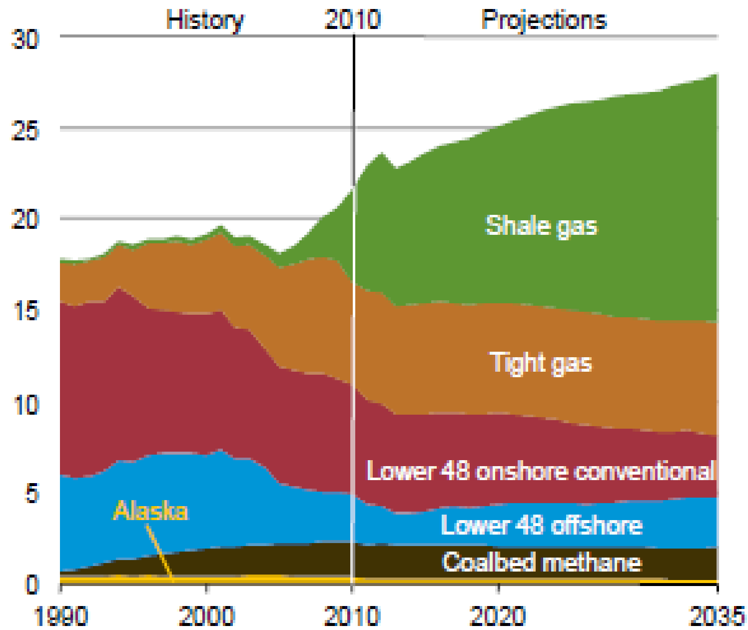


31. In its Annual Energy Outlook 2012, the EIA indicates that the largest contributor to natural gas production growth in the United States will be shale gas for the next two and a half decades. Specifically, the EIA expects gas production in the US Northeast[7] to increase from about 1.5 tcf (4.2 bcf/d) in 2010 to approximately 5.4 tcf (14.7 bcf/d) in 2035[8]. Marcellus production is expected to account for

[7] The US Northeast production region includes the Marcellus and Utica shale formations.
[8] DOE/EIA-0383(2012) Annual Energy Outlook 2012 with Projections to 2035, June 2012.

roughly 3.0 tcf (8.2 bcf/d) of this projected production increase. Furthermore the EIA is projecting production growth, relative to other natural gas production regions in the US, to be greatest for the Northeast region. On the following page, Figure 7 provides a chart from the EIA Annual Energy Outlook which shows total US natural gas production projections to 2035~~.~~ and Figure 8, taken from the same report, shows a regional breakdown of projected natural gas production for the years 2010 and 2035.

Figure 7: Natural Gas Production by Source 1990-2035 (tcf)



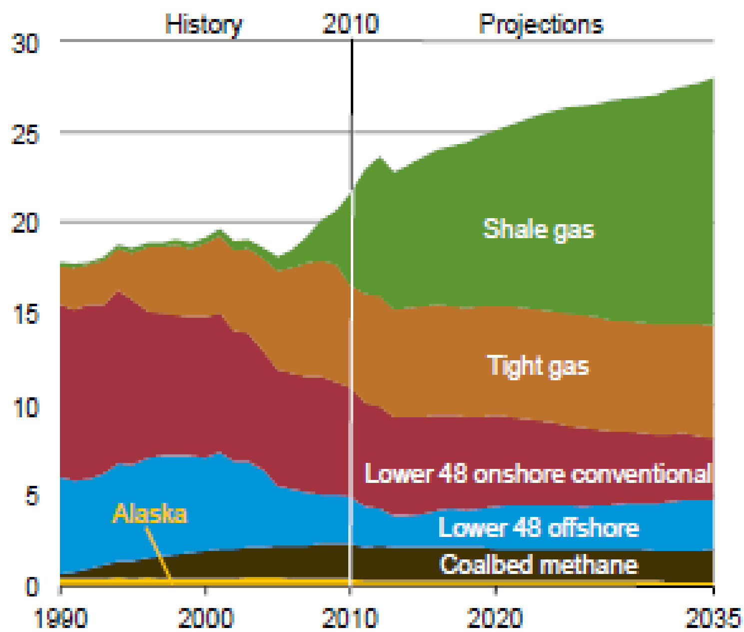
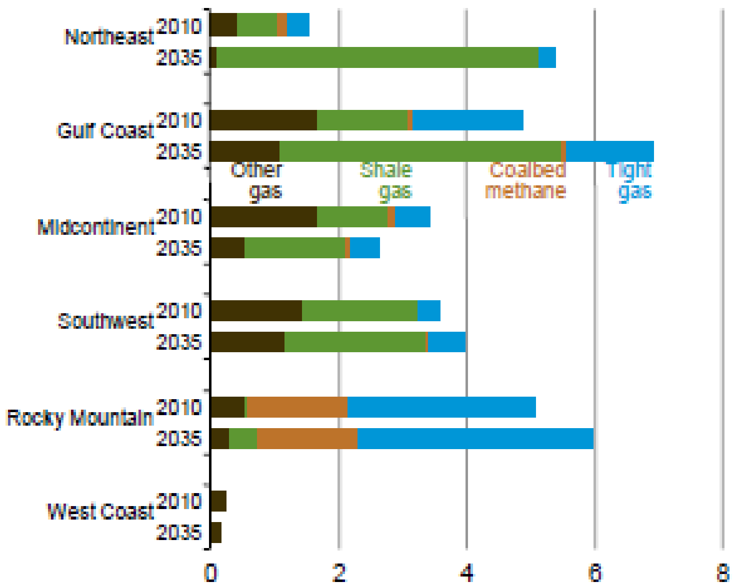
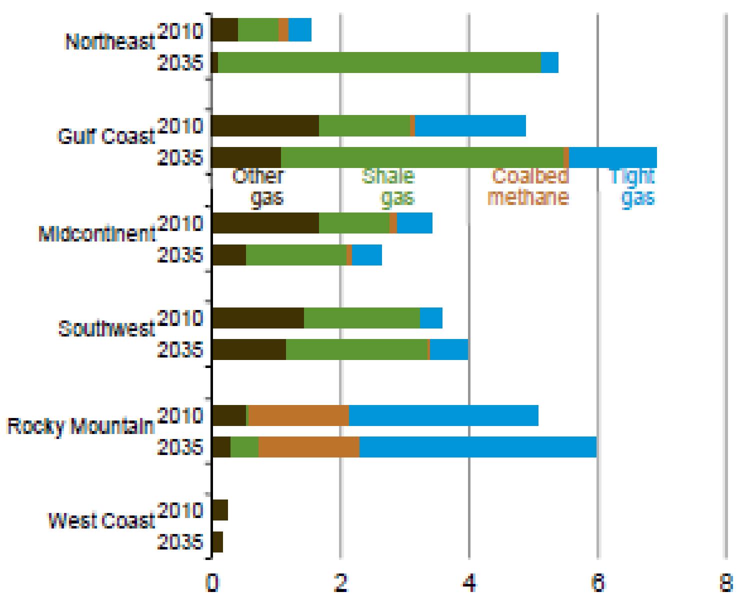


Figure 8: Lower 48 Onshore Natural Gas Production by Region 2010 & 2035 (tcf)



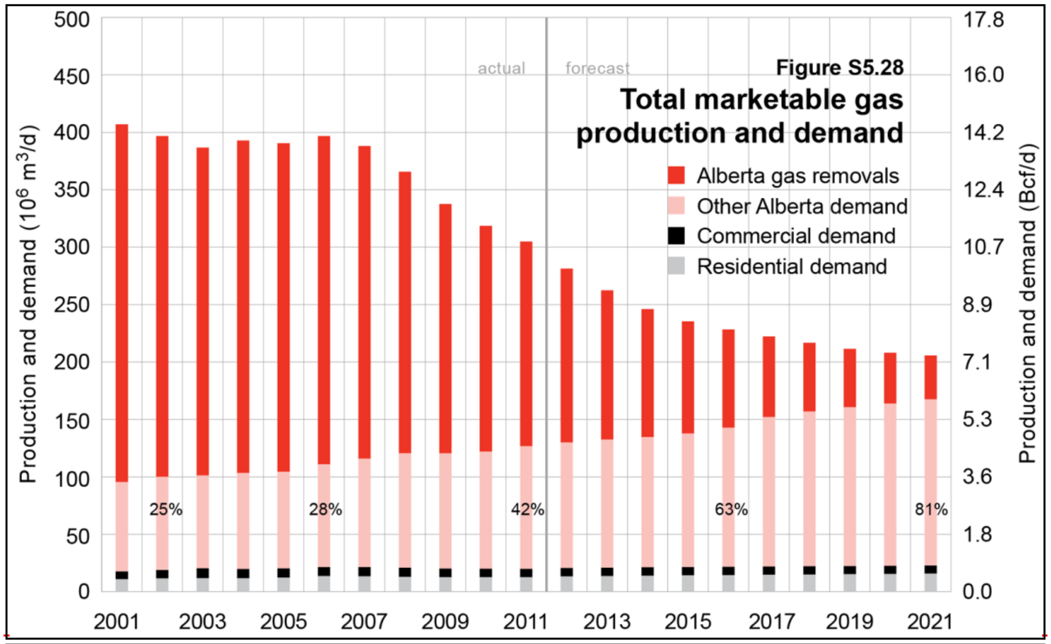


32. In addition the supply outlook for Alberta exports continues to be bleak. A recent report from the Energy Resources Conservation Board ("ERCB") of Alberta expects continued declines in production within Alberta in addition to increases in

intra-Alberta demand[9]. Figure 9 below provides a chart from the ERCB report which shows projections for Alberta conventional gas production, Alberta demand and gas available for export from Alberta. Table 3 on the following page provides data for select years from
Figure 9.

[9] ERCB ST98-2012 Alberta's Energy Reserves 2011 and Supply/Demand Outlook 2012-2021.

Figure 9: ERCB Production Forecast



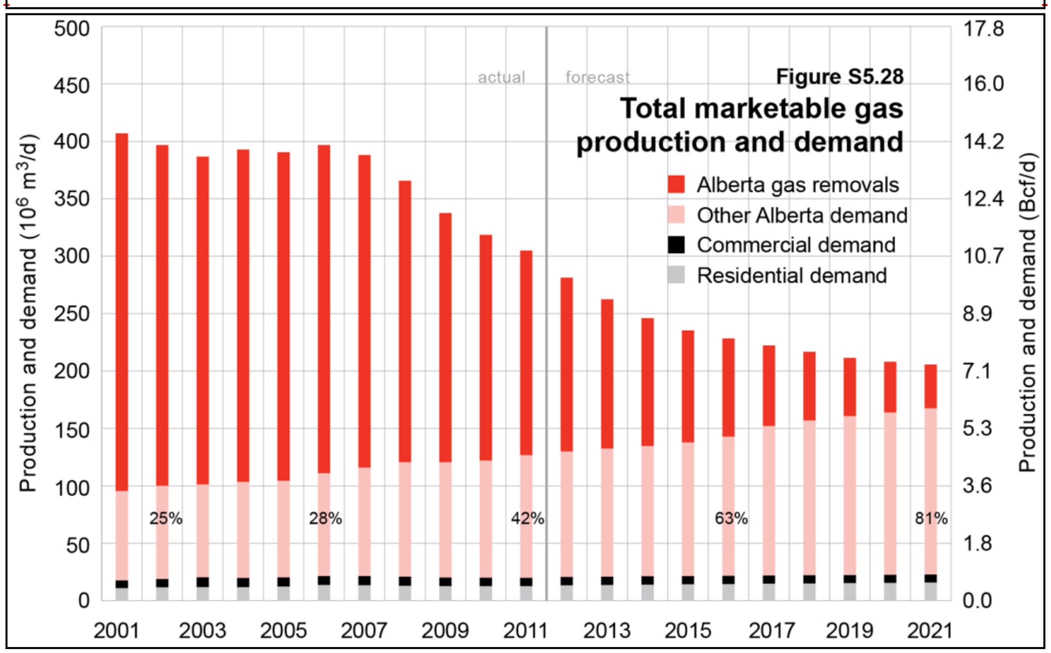


Table 3: Projections From ERCB Report

bcf/d	Production	Demand	Removals (Gas Exports)
2012	10.0	4.6	5.4
2016	8.1	5.1	3.0
2021	7.3	5.9	1.4

bcf/d	Production	Demand	Removals (Gas Exports)
2012	10.0	4.6	5.4
2016	8.1	5.1	3.0
2021	7.3	5.9	1.4

33. By 2021 the ERCB is projecting a 75% decline in the amount of natural gas available for export from Alberta. Put another way the ERCB is projecting that by 2021 the amount of conventional gas available for export from Alberta will be slightly greater than the total amount of Western Canadian supplies currently required by the Company to meet winter demands.

34. The ERCB report focuses on conventional gas production in Alberta and does not include projections for potential shale gas production within Alberta or natural gas supplies from British Columbia which connect to the pipeline system in Alberta. While these supply sources could serve to offset declines in the amount of gas available for export from Alberta there is uncertainty around where this gas will flow. For example, there is the possibility that in the future gas produced in the ~~Western Canadian Sedimentary Basin (“WCSB”),~~WCSB, in Alberta and British Columbia or both may flow westward for export to markets overseas. The extent to which this occurs or the gas otherwise flows eastward will be dependent on access to overseas markets and natural gas pricing.

Expected Gas Supply Benefits

35. The GTA Project will enhance the reliability of various elements of the natural gas supply chain including upstream supply, entry points to the distribution system, and downstream distribution infrastructure.

36. The Company continues to be concerned about its reliance on unsecured supplies[10], particularly peaking supplies and DP delivered supplies and the availability of STFT in the future. Expectations for continual declines in production from the WCSB are also a concern. The Enbridge supply portfolio currently has limited connectivity to the emerging basins in the US Northeast. The Company believes that the proximity of these emerging basins and the shorter distance of haul required to deliver these emerging supplies to market make them ideal for displacing STFT and peaking supplies.

37. In light of these expectations and uncertainties the Company believes it is prudent to act now in order to provide additional supply diversity for its gas supply portfolio. Approval of the GTA Project facilities will provide a means through which the aforementioned risks and concerns related to upstream supplies can be mitigated and provide economic benefits to ratepayers.

38. The GTA Project will provide an additional 800,000 GJ/d of upstream takeaway capacity from Parkway to the largest market served by the Company. The new entry point resulting from the project will provide access to supplies from Dawn or other sources, for example, supplies sourced at Niagara Falls. Once in service the GTA Project will allow the Company to alter its gas supply portfolio to take advantage of these opportunities.

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[10] Unsecured supplies include Curtailment, Peaking Supplies and Direct Purchase Delivered Supplies.

~~39.~~ Once GTA Project facilities are in service the Company expects to reduce reliance on peaking supplies and STFT and source additional supply from Dawn and Niagara. In addition, the Company is contemplating providing DP customers with the option to deliver gas at Dawn and transport these supplies to Parkway via an assignment of capacity from the Company. The Company has been in discussions with its DP customers in an effort to gauge interest in alternative delivery points for supply. Allowing delivery of DP supply at Dawn can be expected to produce a benefit by reducing the cost of transport. For an Ontario T-Service customer supply costs would be reduced by the incremental cost of flowing gas from Parkway to the Enbridge CDA. In addition, these supplies would be underpinned by firm capacity

39. due to the assignment and procured at a liquid hub thereby increasing security of supply.

40. Enbridge recently bid into Union's April 24, 2012 Open Season for 400,000 GJ/d of capacity from Dawn to Parkway in 2015. The awarding of this capacity is contingent on regulatory approval of the GTA Project. Enbridge also intends to bid into an upcoming TransCanada open season for capacity from Niagara Falls to Parkway for service in 2015.

41. Assuming a continuation of existing contracting practices, the Company expects it would require approximately 519 TJ/d of STFT and 158 TJ/d of peaking supplies in order to meet projected peak day demand in 2014. These peak day requirements are outlined in Table 2 ~~above.~~on page 11 of this exhibit. The Company has not yet determined peak day requirements for 2015[11] and consequently is basing the benefits calculations on the expected gas supply portfolio for 2014.

42. The Attachment ~~1~~[12] provides details and assumptions related to the calculation of the expected gas supply benefits should the GTA Project be approved. Tables A1 to A3 provided in the Attachment, list toll, fuel, and commodity pricing assumptions. By replacing approximately 100,000 GJ/d of peaking supplies and 300,000 GJ/d of STFT to the Enbridge CDA with supplies sourced from Dawn and Niagara the Company expects to generate gas supply savings of approximately $410 million over the 2015 to 2025 timeframe for system gas customers. In the Attachment, Table A4 provides details for this calculation. A shift in DP delivery point obligations can be expected to generate benefits as well.

[11] Peak day requirements for 2015 will be provided when the Company applies for 2015 rates.
[12] The Attachment has been updated with the amended evidence filed with Update No. 2. The Expected Gas Supply Benefits Update can be found on page 21 of this schedule.

200,000 GJ/d of DP deliveries at Dawn rather than the Enbridge CDA[13] could generate savings of approximately $101 million over the 2015 to 2025 timeframe for DP customers. Table A4 provides details for this calculation as well. Overall the Company expects a total savings of $511 million over the 2015 to 2025 timeframe~~.~~[14]. The calculation of the GTA Project profitability index includes those benefits attributable to the contracting shift contemplated by the Company and the benefits from the DP delivery point shift.

43. Approval of the GTA Project will provide significant enhancements to the gas supply portfolio. It will improve diversity and flexibility through access to Marcellus and Dawn supply, mitigate risk associated with non-renewable long haul transport services, and reduce gas supply costs.

[13] Deliveries to the Enbridge CDA are assumed to be procured at Dawn.
[14] The expected gas supply savings have been updated with the amended evidence filed with Update No. 2 and can be found on page 21 of this schedule.

~~Table A1: Toll Assumptions~~

Toll Assumptions	Demand Charge ($/GJ)	Commodity Charge ($/GJ)
STFT Empress-EGD CDA[1]	2.24	0.00
Dawn-EGD CDA[1]	0.25	0.01
Peaking 1[2]	0.66	Iroquois + $0.00
Peaking 2[2]	0.71	Iroquois + $0.19
Peaking 3[2]	0.89	Dawn + CDA Transport + $0.24
M12 Dawn-Parkway[3]	0.10	0.00
Niagara-Parkway[4]	0.14	0.01

[1] 2012 Interim Toll.

[2] Pricing based on peaking RFP responses for 12'-13' winter service.

[3] Based on high end of range provided in Union's April 24, 2012 Open Season.

[4] Based on system average unit costs provided in TransCanada Pipelines Limited Application for Approval of Revised Mainline Interim 2011 Tolls dated January 25, 2011 and an estimated distance of 130km from Niagara to Parkway.

~~Table A2: Fuel Ratio Assumptions~~

Fuel Ratio Assumptions (%)	January	February	March	April	May	June	July	August	September	Octob
Empress-EGD CDA[1]	3.950	4.350	2.100	1.000	1.450	1.000	0.950	1.350	1.100	1.650
Dawn-EGD CDA[1]	0.500	0.420	0.220	0.130	0.060	0.000	0.150	0.180	0.020	0.090
M12 Dawn-Parkway[2]	1.075	0.990	0.853	0.763	0.623	0.328	0.328	0.328	0.347	0.690
Niagara-Parkway[3]	0.350	0.250	0.140	0.070	0.000	0.000	0.120	0.130	0.000	0.030

[1] Actual fuel ratios from December 2011 to November 2012.
[2] Fuel ratios per M12 rate schedule effective October 1, 2012. Dawn to Parkway (Consumers).
[3] Actual fuel ratios from December 2011 to November 2012. Assumes Niagara to EGD CDA fuel ratios.

~~Table A3: Commodity Price Assumptions (November to March Averages)~~

Commodity Price Assumptions - Average for the Winter ($/GJ)[1]	Empress	Dawn/Niagara[2]	Iroquois
2015/2016	4.19	4.66	5.92
2016/2017	4.45	4.84	6.13
2017/2018	4.60	5.05	5.89
2018/2019	4.67	5.15	5.70
2019/2020	4.73	5.21	5.76
2020/2021	4.79	5.28	5.81
2021/2022	4.85	5.33	5.87
2022/2023	4.90	5.39	5.93
2023/2024	4.96	5.43	5.98
2024/2025	5.00	5.45	6.02
2025/2026	5.04	5.51	6.06

[1]Commodity prices based on forward curves as at October 12, 2012.

[2] Assumes gas will land at Niagara at a Dawn equivalent price.

EXPECTED GAS SUPPLY BENEFITS UPDATE

Expected Gas Supply Benefits

44. The purpose of this evidence is to provide an update to the gas supply benefits Enbridge expects to generate through gas supply portfolio changes once the GTA Project facilities are put into service. This update is provided pursuant to amendments made to the GTA Project Leave to Construct Application ("GTA LTC") which were filed with the Ontario Energy Board (the "Board") on February 12, 2013.

45. Commensurate with the refined scope of the GTA LTC, the expected contracting practice with the GTA Project facilities in service as originally filed have been updated to take into account the following changes:
   - The creation of a new single point distributor delivery area at the Bram West Interconnect which is to be called the Bram West CDA;
   - An Enbridge contract for 800,000 GJ/d of capacity on the TransCanada Mainline from the Union Parkway Belt to Bram West CDA[15];
   - The creation of a new single point distributor delivery area called Parkway Enbridge CDA;
   - An Enbridge contract for 200,000 GJ/d of capacity on the TransCanada Mainline from Niagara Falls to Parkway Enbridge CDA[16]; and
   - The utilization of updated tolls for the calculation of gas supply benefits. The tolls utilized for this update, including those to the new distributor delivery areas as provided by TransCanada, are based on TransCanada's Restructuring Proposal tolls for 2013, as filed on June 29, 2012 in National

[15] Contract is contemplated in conjunction with all necessary regulatory approvals for required facilities.
[16] Contract is contemplated in conjunction with all necessary regulatory approvals for required facilities.

Energy Board ("NEB") hearing RH-003-2011[17], and tolls provided by Union Gas on April 2, 2013 in Board's file EB-2013-0074[18].

46. By replacing approximately 100,000 GJ/d of peaking supplies and 300,000 GJ/d of STFT to the Enbridge CDA the Company expects to generate gas supply savings of approximately $361 million over the 2015 to 2025 timeframe for system gas customers. The contemplated 200,000 GJ/d shift in DP delivery point obligations is expected to generate savings of approximately $31 million over the 2015 to 2025 timeframe[19]. Overall the Company expects a total savings of approximately $392 million over the 2015 to 2025 timeframe. The primary reason for the change in the expected gas supply benefits relative to the expected benefits as originally filed is due to the introduction of the Union Parkway Belt to Bram West CDA contract and the utilization of updated tolls.

47. The update includes the impact of the Union Gas Parkway West Project application and the impact of the facilities applied for in the Brantford-Kirkwall/Parkway D Project application. The Company believes its estimate of expected gas supply benefits is conservative for the following reasons:

- The assumption that Direct Purchase volumes are sourced at and flow on short haul from Dawn when in reality it is likely that some direct purchase flows utilize discretionary services from Empress. Absent the GTA Project, which provides a capacity expansion into the Enbridge distribution system and on the TransCanada Mainline, Direct Purchase volumes would utilize IT and/or STFT throughout the winter months due to existing capacity constraints east of Parkway during periods of high demand;

[17] Exhibit B40-TransCanada PipeLines Limited-Revisions to Reflect TransCanada's 2013 Throughput Forecast. (A42497).
[18] Union Gas Limited's Brantford-Kirkwall/Parkway D Project application.
[19] Deliveries to the Enbridge CDA are assumed to be procured at Dawn.

- The assumption that STFT is 100% utilized. Absent the GTA Project the Company expects to continue to contract for STFT. However utilization of this capacity is expected to be less than 100%. For example, Table 4 below outlines the average landed cost of STFT over the 2015 to 2025 timeframe assuming various levels of utilization[20].

Table 4: Average Landed Cost of STFT – 2015 to 2025

Utilization (Load Factor)	100%	66%	31%
Average Landed Cost ($/GJ)	7.47	8.80	13.19

48. The Company believes it must contract STFT for a minimum term of three months. Consequently, as the load profile for the distribution system becomes "peakier" utilization of STFT is likely to be lower as additional amounts of STFT are contracted for each year. As this occurs Enbridge customers would be bearing a greater proportion of Mainline costs relative to utilization of STFT.

49. The Attachment provides updated details and assumptions related to the calculation of the expected gas supply benefits should the GTA Project be approved. Tables A1 to A3 provided in the Attachment list toll, fuel, and commodity pricing assumptions respectively. In the Attachment, Table A4 provides the updated benefits calculations.

Implications of TransCanada Restructuring Proposal Decision& Recent Open Season

50. On March 27, 2013 the NEB issued a decision ("Decision") related to TransCanada's September 1, 2011 application for approval of the Business and

[20] Average landed costs are calculated utilizing the same toll, fuel ratio, commodity, flow and contracting assumptions as the updated benefits calculations in this exhibit.

Services Restructuring Proposal and Mainline Final Tolls for 2012 and 2013. This Decision establishes the framework for the determination of Mainline tolls for a five year period beginning in 2013 and ending in 2017. Consequently, the Decision will impact the evidence submitted in this filing. Once the full impact of this Decision is known Enbridge will file an update to this evidence. While final Mainline tolls are not yet known there are several aspects of the Decision which have implications for Enbridge's gas supply portfolio. In addition recent open season announcements by TransCanada have implications for the amount of discretionary services available on the Mainline in the future.

51. The Decision establishes a baseline toll from Empress to Dawn from which all other tolls are derived. In addition the Decision provides TransCanada with greater discretion in determining the toll to be charged for STFT and IT. Specifically, TransCanada is able to set the minimum bid floor for IT service at whatever level it sees appropriate. Bid floors for STFT are to be set at a minimum of the 100% load factor toll for the corresponding path with no upper limit on the bid floor for this service. In its Decision the NEB indicated that:

> *"…the existence of a cost-based recourse rate, the FT toll, provides an implicit cap for discretionary shippers that need guaranteed access to the Mainline to meet their requirements. These shippers may elect to contract for FT service and pay the annual costs related to the capacity they need. Alternatively, they may find features of the IT and STFT services more attractive and accept the risk that at certain times of the year they may have to choose between paying high discretionary tolls or not using the Mainline."*[21]

[21] National Energy Board, Reasons for Decision, TransCanada PipeLines Limited, Nova Gas Transmission Ltd., and Foothills Pipe Lines Ltd. RH-003-2011, page 127.

52. TransCanada recently held an Existing Capacity Open Season for non-renewable service on various Mainline paths with service terminating in October 2015[22]. In addition TransCanada also announced that it will be holding a binding open season to obtain firm commitments from interested parties for a pipeline – The Energy East Pipeline - to transport crude oil from Western Canada to Eastern Canadian markets[23]. The Energy East Pipeline involves converting approximately 3,000 kilometers of the Mainline to crude oil service in addition to the construction of approximately 1,400 kilometers of new pipeline. According to TransCanada the binding open season is the result of a successful expression of interest phase and subsequent discussions with prospective shippers.

53. These events indicate the very real possibility that capacity on the Mainline will be reduced in the near future. In the event that conversion to oil does occur the amount of STFT and IT available in any given year will likely decrease, all else equal. As indicated in Table 2 (page 11), absent GTA Project facilities the Company expects to rely significantly on STFT in order to meet its peak day demand requirements. In addition the amount of unsecured supply delivered to market by DP customers continues to compose a large portion of peak day demand requirements.

54. The extent to which STFT availability is reduced could limit the availability of this service as a substitute for peaking supplies and firm transportation during the winter. The amount of IT available will likely decrease as well which could impact the reliability of unsecured supplies, particularly during periods of high demand. Increased discretion in pricing of these services in conjunction with a reduction in

[22] Canadian Mainline Existing Capacity Open Seasons, March 26 – April 23, 2013
http://www.transcanada.com/customerexpress/2802.html
[23] The Energy East Pipeline Open Season, April 15, 2013 – June 17, 2013
http://www.transcanada.com/6280.html

Mainline capacity will create increased uncertainty with respect to Enbridge's gas supply portfolio costs as Enbridge would be required to outbid other shippers to access necessary capacity.

55. Enbridge will continue to work with TransCanada and other stakeholders to ensure that the needs of the markets served by Enbridge are met through current and future natural gas infrastructure.

Attachment – Gas Supply Benefits Calculations and Assumptions

Table A1: Toll Assumptions

Toll Assumptions	Demand Toll ($/GJ)	Commodity Toll ($/GJ)
3 Month STFT Empress-EGD CDA[1,5]	2.597	0.000
5 Month STFT Empress-EGD CDA[1,5]	2.424	0.000
Dawn-EGD CDA[1]	0.228	0.000
Peaking 1[2]	0.659	Iroquois + $0.00
Peaking 2[2]	0.707	Iroquois + $0.19
Peaking 3[2]	0.895	Dawn + CDA Transport + $0.24
M12 Dawn-Parkway[3]	0.091	0.000
Niagara-Parkway Enbridge CDA[4]	0.139	0.000
Union Parkway Belt-Bram West CDA[4]	0.067	0.000

[1] 2013 Restructuring Proposal tolls as provided by TransCanada in NEB Hearing Order RH-003-2011 on June 29, 2012 (B40-TransCanada Pipelines Limited-Revisions to Reflect TransCanada's 2012 Throughput Forecast (A42497)). These tolls will be updated once final tolls pursuant to the NEB Decision in RH-003-2011 are provided.

[2] Pricing based on peaking RFP responses for 12'-13' winter service.

[3] Toll provided in EB-2013-0074 Union Gas Brantford-Kirkwall/Parkway D Project application.

[4] 2013 Restructuring Proposal tolls provided by TransCanada based on data provided in NEB Hearing Order RH-003-2011 on June 29, 2012 (B40-TransCanada Pipelines Limited-Revisions to Reflect TransCanada's 2012 Throughput Forecast (A42497)). These tolls will be updated once final tolls pursuant to the NEB Decision in RH-003-2011 are provided.

[5] Empress to EGD CDA Toll calculated as Empress to SMB toll plus SMB to EGD CDA toll times 140% or 150% for 3 month or 5 month service respectively.

Table A2: Fuel Ratio Assumptions

Fuel Ratio Assumptions (%)	January	February	March	April	May	June	July	August	September	October	November	December
Empress-EGD CDA[1]	3.950	4.350	2.100	1.000	1.450	1.000	0.950	1.350	1.100	1.650	2.400	3.350
Dawn-EGD CDA[1]	0.500	0.420	0.220	0.130	0.060	0.000	0.150	0.180	0.020	0.090	0.360	0.250
M12 Dawn-Parkway[2]	1.075	0.990	0.853	0.763	0.623	0.328	0.328	0.328	0.347	0.696	0.764	0.949
Niagara-Parkway Enbridge CDA[3]	0.350	0.250	0.140	0.070	0.000	0.000	0.120	0.130	0.000	0.030	0.280	0.120
Union Parkway Belt-Bram West CDA[4]	0.160	0.120	0.070	0.030	0.000	0.000	0.070	0.080	0.000	0.000	0.120	0.010

[1] Actual fuel ratios from December 2011 to November 2012.
[2] Fuel ratios per M12 rate schedule effective October 1, 2012. Dawn to Parkway (Consumers).
[3] Actual fuel ratios from December 2011 to November 2012. Assumes Niagara to EGD CDA fuel ratios.
[4] Actual fuel ratios from December 2011 to November 2012. Assumes Union Parkway Belt to EGD CDA fuel ratios.

Table A3: Commodity Price Assumptions (November to March Averages)

Commodity Price Assumptions - Average for the Winter ($/GJ)[1]	Empress	Dawn/Niagara[2]	Iroquois	EGD CDA
2015/2016	4.19	4.66	5.92	4.90
2016/2017	4.45	4.84	6.13	5.08
2017/2018	4.60	5.05	5.89	5.30
2018/2019	4.67	5.15	5.70	5.39
2019/2020	4.73	5.21	5.76	5.45
2020/2021	4.79	5.28	5.81	5.52
2021/2022	4.85	5.33	5.87	5.58
2022/2023	4.90	5.39	5.93	5.64
2023/2024	4.96	5.43	5.98	5.67
2024/2025	5.00	5.45	6.02	5.70
2025/2026	5.04	5.51	6.06	5.76

[1] Commodity prices based on forward curves as at October 12, 2012.

[2] Assumes gas will land at Niagara at a Dawn equivalent price.

Table A4: GTA Project Benefit s Calculations ($ millions)

			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Current Contracting Practice													
Service	STFT	Demand Charges	16.4	75.2	74.5	74.5	74.5	75.2	74.5	74.5	74.5	75.2	74.5
Path	Empress to EGD CDA	Fuel Charges	0.9	4.5	4.7	4.8	4.9	5.0	5.0	5.1	5.1	5.2	5.2
Contract Demand (gj/d)	294,494	Commodity Charges	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Commodity Cost	26.9	126.4	132.7	134.8	136.7	139.9	140.3	142.0	143.5	146.4	146.2
		Total Cost	44.2	206.1	211.9	214.1	216.1	220.1	219.7	221.5	223.1	226.9	225.8
Service	Peaking Supplies	Demand Charges	0.1	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Path	CDA Delivered Supply	Fuel Charges	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Contract Demand (gj/d)	105,506	Commodity Premium	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
		Commodity Cost	0.0	5.7	5.9	5.8	5.9	5.9	6.0	6.1	6.1	6.2	6.2
		Total Cost	0.1	6.8	7.0	6.9	6.9	7.0	7.1	7.1	7.2	7.2	7.3
Service	Direct Purchase	Demand Charges	2.8	16.7	16.6	16.6	16.6	16.7	16.6	16.6	16.6	16.7	16.6
Path	Dawn to EGD CDA	Fuel Charges	0.2	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8
Contract Demand (gj/d)	200,000	Commodity Charges	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Commodity Cost	55.8	336.2	349.3	365.7	367.2	374.6	377.7	381.9	386.1	388.1	390.0
		Total Cost	58.7	353.5	366.6	383.1	384.5	392.0	395.0	399.3	403.4	405.5	407.3
		A - Total Cost	103.0	566.4	585.4	604.1	607.5	619.1	621.8	627.9	633.7	639.6	640.4
Expected Contracting With GTA Project Approved													
Service	Union M12 - EGD	Demand Charges	1.1	6.7	6.6	6.6	6.6	6.7	6.6	6.6	6.6	6.7	6.6
Path	Dawn to Parkway	Fuel Charges	0.0	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Contract Demand (gj/d)	200,000	Commodity Charges	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Commodity Cost	0.0	31.9	32.7	34.1	34.2	35.3	35.2	35.6	36.0	36.6	36.3
		Total Cost	1.1	38.9	39.7	41.1	41.2	42.3	42.2	42.6	43.0	43.6	43.4
Service	TCPL FT - EGD	Demand Charges	1.7	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Path	Niagara to Parkway Enbridge CDA	Fuel Charges	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Contract Demand (gj/d)	200,000	Commodity Charges	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Commodity Cost	30.1	112.6	116.0	121.0	121.5	124.6	124.9	126.2	127.6	129.0	128.9
		Total Cost	31.8	123.0	126.3	131.4	131.9	135.0	135.3	136.6	138.0	139.4	139.3
Service	Union M12 - Direct Purchase	Demand Charges	1.1	6.7	6.6	6.6	6.6	6.7	6.6	6.6	6.6	6.7	6.6
Path	Dawn to Parkway	Fuel Charges	0.5	2.3	2.4	2.5	2.5	2.5	2.5	2.6	2.6	2.6	2.6
Contract Demand (gj/d)	200,000	Commodity Charges	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Commodity Cost	55.8	336.2	349.3	365.7	367.2	374.6	377.7	381.9	386.1	388.1	390.0
		Total Cost	57.4	345.1	358.3	374.8	376.3	383.8	386.9	391.1	395.3	397.3	399.2
Service	TCPL Short Haul - EGD & Direct Purchase	Demand Charges	3.3	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7	19.7
Path	Union Parkway Belt to Bram West CDA	Fuel Charges	0.1	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Contract Demand (gj/d)	800,000	Commodity Charges	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Commodity Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Total Cost	3.3	20.1	20.0	20.1	20.1	20.1	20.1	20.1	20.1	20.1	20.1
		B - Total Cost	93.6	527.1	544.3	567.4	569.5	581.3	584.4	590.4	596.3	600.5	602.0
		Savings (A-B)	9.3	39.3	41.1	36.6	38.1	37.9	37.5	37.5	37.4	39.0	38.5

Attachment – Gas Supply Benefits Calculations and Assumptions

Table A1: Toll Assumptions

Toll Assumptions	Demand Toll ($/GJ)	Commodity Toll ($/GJ)
FT Empress-EGD CDA[1]	1.677	0.000
Dawn-EGD CDA[1]	0.252	0.000
Peaking 1[2]	0.682	Iroquois + $0.00
Peaking 2[2]	0.731	Iroquois + $0.19
Peaking 3[2]	0.926	Dawn + CDA Transport + $0.24
M12 Dawn-Parkway[3]	0.091	0.000
Niagara-Parkway Enbridge CDA[4]	0.164	0.000
Union Parkway Belt-Bram West CDA[4]	0.093	0.000

[1] 2013-2017 Review and Variance tolls as provided by TransCanada on May 1, 2013 in NEB Hearing Order RH-003-2011.
[2] Pricing based on peaking RFP responses for 12'-13' winter service.
[3] Toll provided in EB-2013-0074 Union Gas Brantford-Kirkwall/Parkway D Project application.
[4] 2013-2017 Review and Variance tolls as provided by TransCanada based on costs and billing determinants provided in the Review and Variance Application filed on May 1, 2013.

Table A2: Fuel Ratio Assumptions

Fuel Ratio Assumptions (%)	January	February	March	April	May	June	July	August	September	October	November	December
Empress-EGD CDA[1]	4.500	5.050	5.000	2.800	1.350	1.000	0.950	1.350	1.100	1.650	2.400	3.500
Dawn-EGD CDA[1]	0.590	0.510	0.760	0.400	0.240	0.000	0.150	0.180	0.020	0.090	0.360	0.360
M12 Dawn-Parkway[2]	1.086	1.033	0.972	0.802	0.567	0.463	0.451	0.355	0.352	0.697	0.840	0.945
Niagara-Parkway Enbridge CDA[3]	0.420	0.310	0.550	0.300	0.160	0.000	0.120	0.130	0.000	0.030	0.280	0.220
Union Parkway Belt-Bram West CDA[4]	0.250	0.150	0.250	0.180	0.100	0.000	0.070	0.080	0.000	0.000	0.120	0.110

[1] Actual fuel ratios from June 2012 to May 2013.
[2] Fuel ratios per M12 rate schedule effective April 1, 2013. Dawn to Parkway (TCPL).
[3] Actual fuel ratios from June 2012 to May 2013. Assumes Niagara to EGD CDA fuel ratios.
[4] Actual fuel ratios from June 2012 to May 2013. Assumes Union Parkway Belt to EGD CDA fuel ratios.

Table A3: Commodity Price Assumptions

Commodity Price Assumptions - Annual Average ($/GJ)[1]	Empress	Dawn	Niagara	Iroquois	EGD CDA
2015	3.69	4.40	4.30	5.51	4.65
2016	3.85	4.44	4.40	5.62	4.70
2017	4.02	4.57	4.55	5.77	4.83
2018	4.42	4.75	4.72	5.95	5.00
2019	4.47	4.94	5.01	6.00	5.20
2020	4.52	5.03	5.08	6.05	5.28
2021	4.56	5.07	5.12	6.09	5.32
2022	4.60	5.10	5.16	6.12	5.36
2023	4.64	5.15	5.20	6.17	5.40
2024	4.68	5.15	5.24	6.21	5.40
2025	4.72	5.19	5.28	6.24	5.44

[1]Commodity prices based on forward curves from OpenLink as at May 6, 2013.

Table A4: GTA Project Benefits Calculations ($ millions)

			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Increased Firm Transportation Scenario													
Service	TCPL FT - EGD	Demand Charges	30.1	180.8	180.3	180.3	180.3	180.8	180.3	180.3	180.3	180.8	180.3
Path	Empress-EGD CDA	Fuel Charges	2.1	10.8	11.2	12.3	12.4	12.6	12.7	12.8	12.9	13.1	13.1
Contract Demand	294,494	Commodity Cost	69.2	415.3	432.5	474.9	480.6	487.2	490.3	494.4	499.1	504.8	507.1
		Total Cost	101.4	606.9	624.0	667.5	673.3	680.6	683.2	687.4	692.3	698.6	700.5
Service	Peaking Supplies -EGD	Demand Charges	0.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Path	Empress-EGD CDA	Fuel Charges	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Contract Demand	105,506	Commodity Cost	0.0	6.2	6.4	6.5	6.2	6.3	6.4	6.4	6.4	6.5	6.5
		Total Cost	0.1	7.2	7.3	7.5	7.2	7.3	7.3	7.4	7.4	7.4	7.5
Service	TCPL FT - Direct Pruchase	Demand Charges	16.8	100.8	100.5	100.5	100.5	100.8	100.5	100.5	100.5	100.8	100.5
Path	Empress-EGD CDA, Dawn-EGD CDA	Fuel Charges	1.1	6.0	6.2	6.8	6.9	7.0	7.0	7.1	7.1	7.2	7.3
Contract Demand	200,000	Commodity Cost	48.6	291.2	302.2	327.6	333.7	338.7	340.8	343.5	346.7	350.0	351.6
		Total Cost	66.5	397.9	408.9	434.9	441.1	446.5	448.3	451.1	454.3	458.0	459.3
		A-Total Cost	168.0	1,012.0	1,040.3	1,109.9	1,121.6	1,134.4	1,138.8	1,145.9	1,154.0	1,164.1	1,167.3
Expected Contracting With GTA Project Facilities Approved													
Service	Union M12 - EGD	Demand Charges	1.1	6.7	6.6	6.6	6.6	6.7	6.6	6.6	6.6	6.7	6.6
Path	Dawn-Parkway	Fuel Charges	0.2	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Contract Demand	200,000	Commodity Cost	25.8	158.6	162.8	168.9	176.0	179.4	180.3	181.6	183.2	183.8	184.5
		Total Cost	27.2	166.4	170.7	176.8	183.9	187.4	188.3	189.6	191.1	191.8	192.5
Service	TCPL FT - EGD	Demand Charges	2.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Path	Niagara Falls-Enbridge Parkway CDA	Fuel Charges	0.1	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Contract Demand	200,000	Commodity Cost	53.5	321.9	331.8	344.6	365.6	372.2	374.1	376.7	379.9	383.8	385.3
		Total Cost	55.6	334.6	344.5	357.3	378.4	385.0	386.8	389.5	392.6	396.6	398.1
Service	Union M12 - Direct Purchase	Demand Charges	1.1	6.7	6.6	6.6	6.6	6.7	6.6	6.6	6.6	6.7	6.6
Path	Dawn-Parkway	Fuel Charges	0.5	2.3	2.4	2.5	2.6	2.6	2.7	2.7	2.7	2.7	2.7
Contract Demand	200,000	Commodity Cost	54.7	325.3	333.9	346.5	360.9	368.0	369.9	372.6	375.7	377.1	378.5
		Total Cost	56.3	334.3	343.0	355.7	370.2	377.3	379.2	381.9	385.1	386.4	387.9
Service	TCPL FT - EGD & Direct Purchase	Demand Charges	4.5	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2	27.2
Path	Parkway to Bram West CDA	Fuel Charges	0.1	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Contract Demand	800,000	Commodity Cost	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Total Cost	4.6	27.8	27.7	27.7	27.8	27.8	27.8	27.8	27.8	27.9	27.8
		B-Total Cost	143.7	863.1	885.8	917.5	960.2	977.5	982.1	988.8	996.6	1,002.7	1,006.2
		Savings (A-B)	24.3	148.9	154.5	192.3	161.4	156.9	156.7	157.1	157.4	161.4	161.1

PROPOSED FACILITIES, OPERATION AND SYSTEM BENEFITS

Note: Elements of this evidence have been updated through the submission of Exhibit A, Tab 3, Schedule 9 (filed on July 22, 2013).

1. The purpose of this evidence is to describe the proposed GTA Project facilities, the intended operation of the facilities, and the operational benefits achieved once in-service.

~~1.~~

Proposed Facilities

2. Enbridge is proposing two segments of natural gas pipelines and associated facilities, referred to as "Segment A" and "Segment B", that will enhance and reinforce the XHP system within the GTA. The pipelines and associated facilities are described below with references to Figures 1 and 2. Figure 1 is a map overview of the proposed facilities in its entirety. Due to the larger map scale in Figure 1, Figure 2 is an expanded overview of the ~~west side of Segment A which includes a shorter pipeline length.~~
Parkway Bypass and NPS 36 tie-in.

3. Segment A consists of:

- A new ~~pressure regulation and odourization facility, known as "Parkway West Gate Station", that will become a new~~NPS 42[1] pipeline, approximately 20.9 km in length, that will originate at the proposed interconnection with ~~Union Gas' Dawn to Parkway~~TransCanada's Mainline transmission system, the "Bram West Interconnect" (Reference 1 in Figure 1~~, also expanded in Figure 2);~~

[1] Or NPS 36. Further detail is provided at Exhibit E, Tab 1, Schedule 2.

- ~~25.7 km of NPS 36 XHP pipe that will originate from the new Parkway West Gate Station~~) and terminate at the existing Enbridge Albion Road Station (Reference 2 in Figure 1);
- An expansion to the existing Albion Road Station (Reference 3 in Figure 1); and~~,~~
- A tie-in to the existing XHP system via:
  - ~~180 m of NPS 36 XHP pipe that will be installed from~~A new connection to Union Gas' Dawn to Parkway system, known as the ~~new~~ Parkway West Gate Station~~ to~~ , adjacent to Union Gas' proposed Parkway West compressor station, and approximately 315 m of NPS 36 pipe to tie into the existing Enbridge NPS 36 Parkway North pipeline (Reference 4 in Figure 1, also expanded in Figure 2); and~~,~~
  -

- o An upgrade to the current valve manifold at the existing Parkway ~~By-Pass~~Bypass to include pressure regulation between the existing NPS 36 Parkway North pipeline and the existing NPS 36 Mississauga Southern Link ("MSL") pipeline that currently operate at different pressures (Reference 5 in Figure 1, also expanded in Figure 2).

4. Segment B consists of:
   - A modification of the existing Keele/CNR Station (Reference 6 in Figure 1);
   - 23 km of NPS 36 XHP pipe that consists of a west-east portion and a north-south portion:
     - o The west-east portion will originate from the existing Keele/CNR Station, proceed east to intersect with the existing NPS 30 Don Valley pipeline (Reference 7a on Figure 1); and~~,~~
     - o The north-south portion will then proceed south to the tie-in point with the existing NPS 36 pipeline north of Sheppard Avenue East (Reference 7b on Figure 1);
   - A new pressure regulation facility, known as "Buttonville Station", located in the Parkway Belt corridor east of Woodbine Avenue, will tie the new NPS 36 pipeline ~~-~~into the existing NPS 30 Don Valley pipeline in the area of the intersection of the two pipelines (Reference 8 on Figure 1); and
   - An expansion to the existing pressure regulation facility at Jonesville Station, located just north of Eglinton Avenue East near Jonesville Crescent that will support the existing NPS 36 pipeline feed to the existing NPS 30 Don Valley pipeline running south from the Jonesville Station (Reference 9 on Figure 1) to Station B.

Safety Considerations for Design of New Pipeline Segments A & B

5. Segments A and Segment B were designed to exceed the most stringent standard according to CSA Z662-11[2]. Segments A and B exceed Class 4 design by 18% and 68% due to the use of thicker wall pipe for the NPS 42 and NPS 36 pipe designs, respectively.

6. Canadian design standard CSA Z662-11 specifies the calculation of hoop stress, which for a given diameter of pipe is a function of both the maximum operating pressure and wall thickness. The hoop stress as a percentage of the specified Minimum Yield Strength ("SMYS") of the pipe (i.e., pipe grade), typically referred to as % SMYS is limited based on Class Location. Subject to certain setback limitations prescribed in the Technical Standard and Safety Authority's ("TSSA") PI-98/01 "Guideline for Locating New Oil and Gas Pipeline Facilities", pipelines in a Class 4 location can be designed to operate up to a pressure equal to 44% SMYS.

7. The % SMYS that a pipeline operates at can be reduced either by increasing the pipe grade and/or by increasing the wall thickness. While the CSA Z662-11 is not prescriptive in terms of these design "trade-offs", the Company's design is consistent with U.K. design practices that emphasize the importance of wall thickness in reducing third party damage, which is a predominant threat in urban areas. Thicker wall pipe also has the benefit of increased resistance to corrosion - another threat to pipeline integrity.

[2] The CSA Z662-11 is the Canadian Standards Association's Oil & Gas Pipeline System standard (2011 edition).

8. Segments A and B have been designed with wall thickness of 19.05 mm and 17.5 mm for the NPS 42 and NPS 36 pipe designs, respectively, in order to ensure a very high level of resistance to both third party damage and corrosion.
9. The design was validated using U.K. Pipeline Risk Assessment Code IGEM TD/2, which quantifies the benefits to be achieved by reduced hoop stress (i.e., % SMYS) and increased wall thickness. For pipelines operating below 50% SMYS, IGEM TD/2 attributes a safety factor of almost 100% for pipelines designed with wall thickness of 16 mm or greater.

10. The Segment A pipeline from Bram West to Albion is designed to operate at 37% SMYS based on the NPS 42 design. With a wall thickness of 19.05 mm, it achieves a near maximum safety benefit attributable to wall thickness, therefore there is very little incremental benefit to be achieved by designing to operate to below 30% SMYS.

11. The NPS 36 pipelines (the 315 m tie-in and Segment B) are designed to operate at 20% SMYS at a normal operating pressure of 3344 kPa (485 psi), or 26% SMYS at maximum operating pressure of 4482 kPa (650 psi). The pipeline was designed to operate at lower stress levels due to its proximity to the NPS 30 Don Valley line and adjacent development.

12. Both Segment A and B will be hydrostatically tested to 100% SMYS and all welds will be non-destructively tested. Once complete, the pipelines will also be inspected internally, using a caliper tool, to check for dents or buckles caused by construction. These measures will ensure the integrity of the pipe material and construction practices prior to commissioning.

13. Once in service, the pipeline pressures and flows will be monitored remotely by Gas Control, who will also have the capability to isolate segments of the pipeline by remotely closing strategically located valves in the event of an incident.

Safety Benefits for Existing Pipelines

14. As described in Exhibit A, Tab 3, Schedule 3, the NPS 26 and NPS 30 Don Valley lines were installed in the late 1960's/early 1970's and operate above 30% SYMS.

15. With existing pipelines, design parameters are pre-determined so achieving relative safety benefits typically focuses on operational parameters. One effective method of obtaining a safety benefit is to lower the operating pressure, provided that the system supply demands can still be met. This was the case in the early 1990's, when the installation of Parkway Phase 2 allowed the operating pressure in the NPS 30 pipeline, that runs along Derry Road and Finch Avenue, to be lowered.

16. As explained in Exhibit A, Tab 3 Schedule 3, page 17, 30% SMYS is the generally accepted boundary below which pipelines subjected to excavation damage are more likely to fail by leak rather than by rupture. The TSSA has endorsed this boundary by limiting the requirements of the recently passed Code Amendment FS-196-12 to pipelines operating at or above 30% SMYS.

17. Once the new facilities are in operation, the operating pressure for the NPS 26 and the NPS 30 Don Valley lines will be reduced to 1896 kPa (275 psi) and 2585 kPa (375 psi) respectively, which will lower the hoop stress levels to below 30% SMYS.

18. Even though these pipelines will be operating below 30% SMYS, the Company intends to continue to perform in-line inspections on them as part of its integrity management program.

Additional Safety Features

19. Both the new and existing pipelines associated with the GTA Project are primarily located in existing utility or rail corridors, not on road allowances. These defined corridors can provide a natural buffer against third party damage.

20. The Company plans to Horizontal Directionally Drill ("HDD") several major road crossings and environmentally sensitive water crossings, totaling approximately 8 km of the 44 km pipeline route. HDD pipeline segments will be at depths much greater than 1.2 m offering additional protection against third party damage.

21. Location specific measures to further reduce the threat of third party damage will be considered during the detailed pipeline design phase, to be completed following Board approval of the project. Such measures will improve the awareness of the pipelines, and may include the installation of buried marker tape, concrete slabs, extra pipeline markers, or other pipeline identifiers. The determination of these additional measures cannot be completed until final design because they are dependent on site specific factors such as pipeline depth, separation from other infrastructure, likelihood of construction activity in the area, etc.

22. The Company believes that with the aggregate design and operational measures described above, the overall safety in the area of influence of the GTA Project will be enhanced.

Operation of the Proposed Facilities

~~In~~

Segment A~~, Parkway~~

~~5.~~23. The Bram West ~~Gate Station~~Interconnect will provide a new entry point into the GTA XHP system. It will supply gas at 6447 kPa (935 psi) to the new ~~25.7~~20.9 km ~~NPS 36~~ pipeline for delivery at Albion Road Station. Albion Road Station is central to the distribution system and will provide tie-in points to two other XHP networks, the NPS 36 Parkway North line and the NPS 30 line (that runs along Derry Road and
Finch Avenue).

~~Segment A~~

24. The pipeline from the Bram West Interconnect to Albion Road Station will be a shared usage pipeline. TransCanada will share usage of the pipeline to transport gas volumes from the Bram West to Albion. At the Albion Road Station, Enbridge gas volumes will be distributed into the existing XHP distribution system.

25. TransCanada will provide a connection for Enbridge at the Bram West Interconnect which will also have provisions for in-line inspection. Albion Road Station will be expanded to accommodate odourization, metering, regulation, and other ancillary equipment.

~~6.~~26. The GTA Project also includes a tie-in from proposed Parkway West Gate Station to the existing NPS 36 Parkway North line via a ~~180~~pipeline approximately 315 m ~~pipe to the NPS 36 Parkway North line and~~ in length. Also, Enbridge proposes to install pressure regulation at the Parkway ~~By-Pass~~Bypass. This short pipeline and ~~facility~~facilities will provide another supply source to the NPS 36 Parkway North pipeline at 3344 kPa (485 psi) and MSL pipeline at 2413 kPa

(350 psi).

~~In~~

Segment B~~, the~~

~~7.~~27. The 23 km of pipeline that runs east from Keele/CNR Station to the Buttonville corridor, then south to Sheppard Avenue East, will provide 3344 kPa (485 psi) to Buttonville and Jonesville Stations. The regulation facilities at Buttonville and Jonesville Stations allow the NPS 30 Don Valley line to be fed from both Victoria Square and Parkway West Gate Stations.

System Benefits of the Proposed Facilities

~~8.~~28. The proposed pipelines and facilities in Segment A and Segment B will result in the following operational benefits:

a. Ability to meet customer growth, and particularly the ability to maintain minimum system pressures at Station B and the downtown Toronto core;
b. Operational flexibility through improved connectivity between the western and eastern parts of the GTA XHP system through the elimination of the west-east bottleneck and the improved ability to accommodate system work provided by the second source of supply to the major XHP supply lines[3];
c. Diversification of supply pathways for two critical distribution lines, NPS 26 and NPS 30 Don Valley pipelines;
d. Mitigation of operational risk through the lowering of operating pressures of the NPS 26 and NPS 30 Don Valley line and the addition of another major supply point into the XHP distribution system capable of supporting Parkway Gate Station; and~~,~~
e. Improved reliability of upstream arrangements by replacing less secure (short term firm and interruptible) long haul transportation from Western

[3] The major XHP supply lines include the NPS 36 Parkway North, NPS 36 MSL, NPS 30 Don Valley, and NPS 26 lines.

~~e.~~ Canada with more secure short haul firm transportation from emerging U.S. North East and Dawn supply.

~~9.~~29. The proposed pipelines and facilities will only meet the full set of objectives outlined in Exhibit A, Tab 3, Schedule 1 if constructed and operated together.

Downstream Distribution System

~~10.~~30. The proposed pipelines will add the XHP pipeline capacity required to meet forecast customer growth. System pressures are forecast to be maintained above minimum requirements until 2025 with the proposed pipelines and facilities in place.

~~Segment A is planned to~~

~~11.~~The pipeline from the Bram West Interconnect will deliver gas to Albion Road Station. This point is central in the distribution area, a preferred location to further distribute gas to downstream HP and IP networks and to back-feed other XHP networks. Given its central location, once the proposed pipelines and facilities are in place, Albion Road Station can help

31. offset a shortfall at either Parkway or Victoria Square Gate Stations, provided the proposed pipelines and facilities are in place.

~~12.~~32. The ~~180 metre~~315 m tie-in and added pressure regulation at Parkway Bypass will diversify supplies by adding another supply point into the system, capable of supporting Parkway Gate Station. It will provide a second source of supply to the NPS 36 Parkway North and NPS 36 MSL lines. This will enhance operational flexibility by providing a back-feed to manage maintenance and integrity management activities and abnormal operating conditions. It will also allow for shutdown of the Parkway Gate Station, if required.

~~13.~~33. Segment B will alleviate the XHP restriction across the existing NPS 26 pipeline and provide a secondary pathway in the transportation of gas from west to east, and vice versa. The direction of gas flow depends on the supply source, use of gas storage volumes, load balancing, and maintenance activities at the time. The improved connectivity between the western and eastern parts of the GTA Influence Area will provide flexibility to balance flows that are increasingly "peakier" based on recent and forecasted customer growth. The capability will aid in the effort to stay within contractual limits.

~~14.~~Segment B creates a continuous NPS 36 line at 3344 kPa (485 psi) from Parkway ~~and Parkway West Gate Stations~~ to Jonesville Station, providing a secondary source as far south as Eglinton Avenue to feed the downtown Toronto core. With the proposed Segment A, this major feed would be normally sourced from Albion Road Station via the proposed Bram West Interconnect. It could also be fed from the existing Parkway Gate Station or through the proposed 315 m tie-in via Parkway West Gate Station providing diversity of supply sources. This pipeline will act as an express lane to move gas volumes to the downtown core and to maintain pressures at Station B, while the existing NPS 30 Don Valley line acts like collector lanes by supplying the flows to the more local district stations. In the case of winter maintenance requirements, the twinning along these two routes will

34. mitigate a significant impact on the supply chain and improve the Company's ability to provide reliable service.

35. The new Buttonville Station, modified Keele/CNR Station, and expanded Jonesville Station and Albion Road Stations includes regulation facilities and tie-ins to adjacent XHP networks which provides enhanced operational flexibility to the existing distribution system and will support maintenance, integrity, and abnormal ~~15.~~ operating conditions. Buttonville Station will provide a second source of supply to the NPS 30 Don Valley line.

~~16.~~The new pipelines will add the capacity needed to support the reduction in operating pressures in the NPS 26 and NPS 30 Don Valley lines. ~~As described in Exhibit A, Tab 3, Schedule 3, these two lines were installed in late 1960's/early 1970's and operate above 30% SMYS. Since the time of installation of these two lines, pipeline design has incorporated increased wall thickness. Increased wall thickness provides an additional element of risk mitigation due to the lower operating stress levels for pipelines with the same pipe grade, diameter, and operating pressure. These two lines operate in Class 3 and 4 locations, defined as high consequence areas ("HCA") by the Technical Standards and Safety Authority ("TSSA"). The NPS 26 line was installed the third phase in the expansion of the NPS 30 line (that runs along Derry Road and Finch Avenue) that had its operating pressure lowered two decades ago. The operating pressure of the NPS 26 line will be lowered to 1,896 kPa (275 psi) and will operate at a common pressure with the NPS 30 line. The operating pressure of the NPS 30 Don Valley line will be lowered to 2,586 kPa (375 psi). The operating pressure reductions for these lines will bring them below 30% SMYS, below the generally accepted "leak-rupture boundary" in industry. Lowering the operating pressure of these lines will reduce the risk of an event causing a~~

36. Lowering the operating pressure of these lines will reduce the risk of an event causing a prolonged outage of the line, and reduce the probability of significant supply chain impacts and the disruption impact to the community.

~~17.~~37. As the anticipated growth materializes over the 2015 to 2025 period considered by this project, it is expected that additional localized HP reinforcement will occur to further support this growth. These reinforcements are included in the Company's 10-year Asset Plan, and are included in the Economic Analysis in Exhibit E, Tab 1, Schedule 1. These reinforcements are not being proposed in this application and will be filed at a later date in parallel with system need.

Entry Points into the Distribution System

38. As demonstrated in Exhibit A, Tab 3, Schedule 3, system risks presently exist where upwards of 270,000 residential customer outages, plus the loss of PEC, may result from a complete station failure at Parkway Gate Station. Parkway West Gate Station will provide diversity to the existing Parkway Gate Station and provide a back-up feed to this station. This means that Parkway West would be able to maintain the reliable supply of natural gas to downstream customers in circumstances that warrant a full or partial shutdown of Parkway Gate Station ~~or~~. In addition, the Bram West Interconnect, along with Segment B, could mitigate the impacts of a capacity shortfall at Victoria Square Gate Station. The additional

~~18.~~ capacity supplied by ~~Parkway West~~the proposed entry points would be immediately available to compensate for lost capacity in the downstream networks.

~~19.~~Parkway West Gate Station will have the ability to displace gas supply flows currently delivered to the GTA through Lisgar Gate Station. As mentioned in Exhibit A, Tab 3, Schedule 3, Lisgar, the oldest gate station in all Enbridge franchise areas, is operated on cold winter days approaching peak day demand. Otherwise, Lisgar is typically operated as a district station. Similar to the decommissioning of Union Gas' Trafalgar Compressor Station one block west, Enbridge expects to downgrade this site to a district station to re-purpose the asset and extend its asset life. This will be possible once the Parkway West facility is in place. The

39. re-purposing of Lisgar Gate Station is not included in this application; however, it is anticipated that it will be included in the Asset Management Plan at a future date.

~~20.~~40. ~~Parkway~~Bram West ~~Gate Station~~Interconnect will provide another major interconnection with the upstream system to access supplies from Dawn or other sources, for example, supplies sourced at Niagara Falls. In conjunction with the Segment A pipeline from Bram West to Albion, it will be capable of delivering additional gas supply volumes, up to 800~~,000 GJ~~ TJ/d, to Albion Road Station for further delivery downstream which is further described below.

~~21.~~41. In combination, the proposed facilities provide alternate supply sources for all of the major XHP supply lines within the GTA, increasing the diversity of path and reliability of the supply chain.

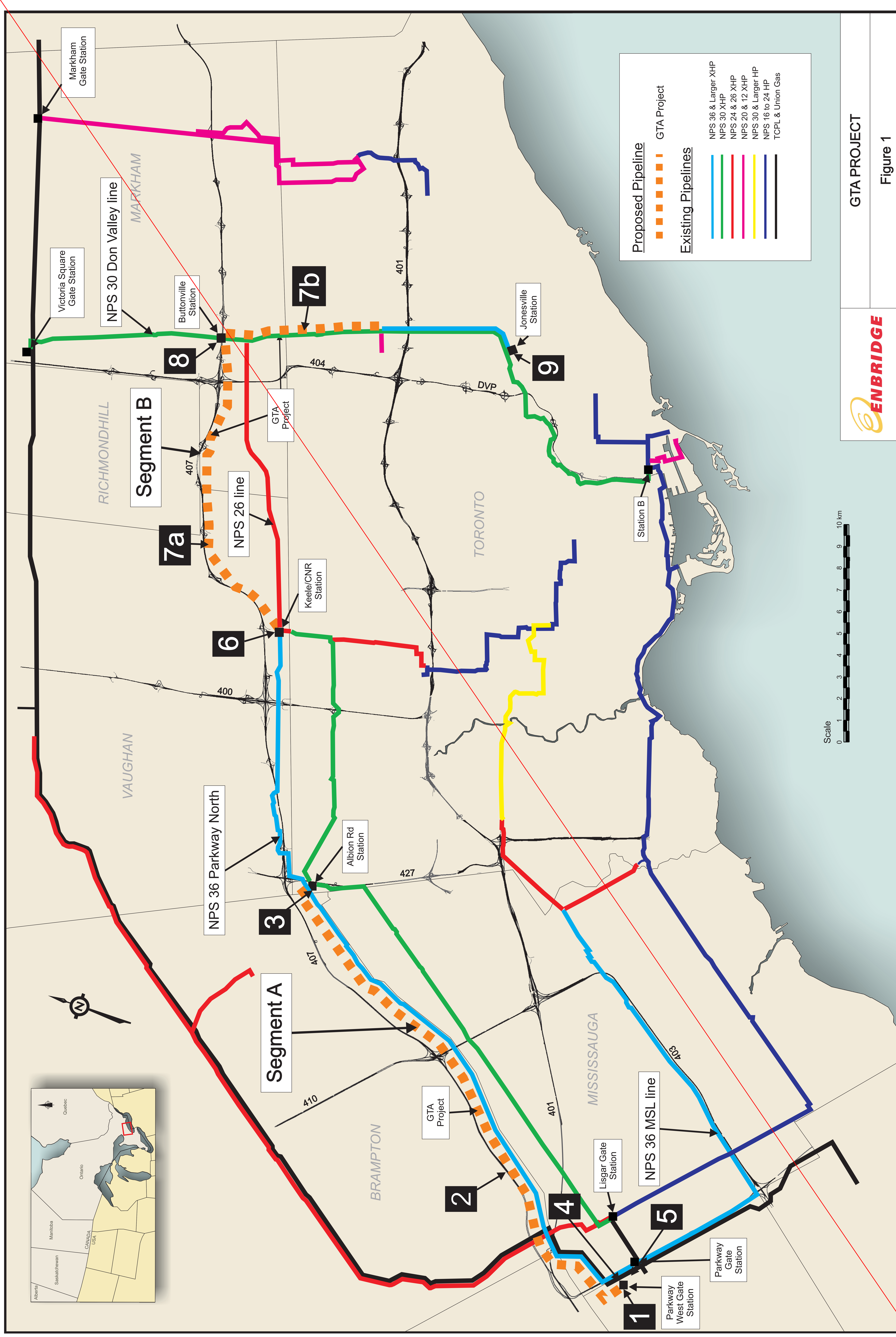
Upstream Transportation

~~22.~~42. Segment A will provide a means to reduce the Company's reliance on discretionary services and facilitate greater flexibility in procuring gas supply and distributing it to key locations in the distribution system. It will have the capacity to bring an additional 800 TJ/d into the system to support customer growth. As described in Exhibit A, Tab 3, Schedule 5, the Company will be able to reduce its reliance on less secure (short term and interruptible) long haul transportation from Western Canada with more secure short haul firm transportation from emerging U.S. North East and Dawn supplies. ~~In addition to increased reliability, the gas supply benefits are estimated to be approximately than $500 million over the 2015 to 2025 period, using the assumptions outlined in Exhibit A, Tab 3, Schedule 5.~~

~~23.~~43. Beyond the GTA, it is expected that the addition of the proposed pipelines and facilities will assist in system reliability in other parts of the Enbridge franchise. The GTA has the only distribution system connected to both Union Gas and TransCanada systems. The flexibility and diversity provided by the new major entry point, pipelines, and associated facilities could provide the Company the ability to accept delivery shortfalls within the GTA and free up gas supply required in other areas, such as other regions within the Central Distribution Area ("CDA") and Eastern Distribution Area ("EDA") that do not have diversified upstream supplies.

~~24.~~44. Throughout this application, the Company has described how the proposed pipelines and facilities are required to support the customer growth forecast to 2025, enhance the diversity and flexibility of the gas supply chain, and support the operational risk management challenges in maintaining safe and reliable delivery to customers.

Filed: 2012-12-21
EB-2012-0451
Exhibit A
Tab 3
Schedule 6
Attachment
Figure 1



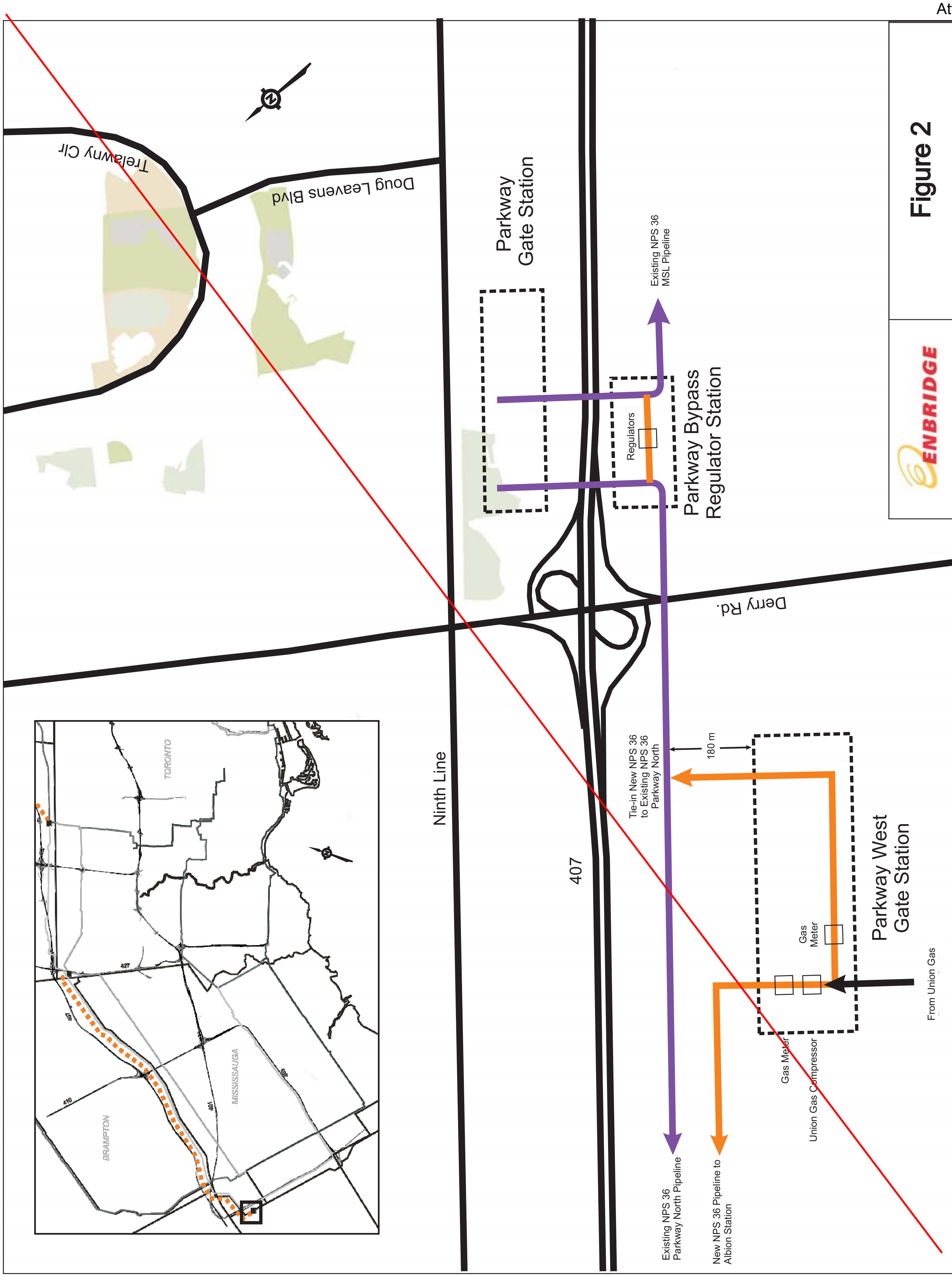
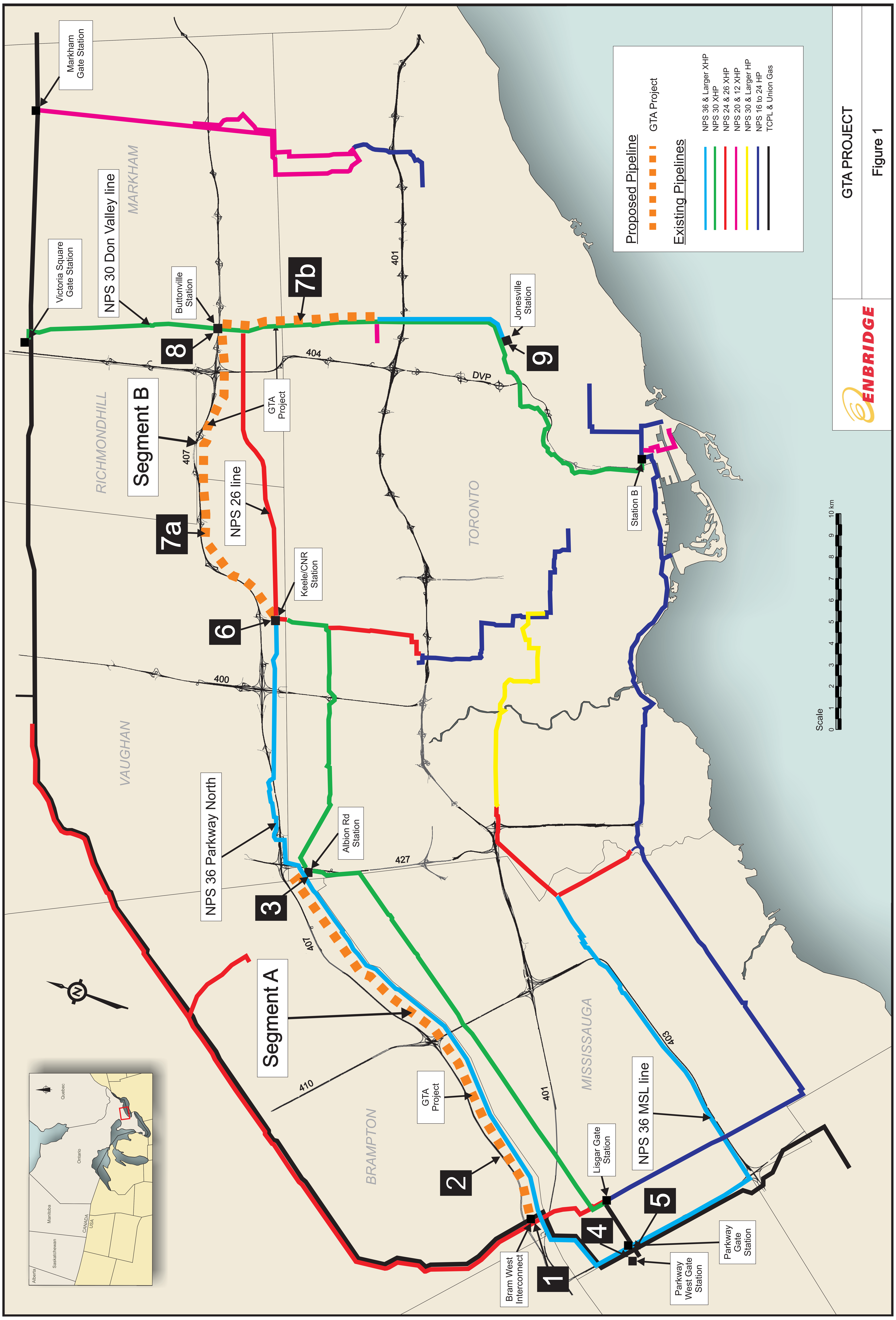


Figure 2
ENBRIDGE
Trelawny Cir
Doug Leavens Blvd
Parkway Gate Station
Existing NPS 36 MSL Pipeline
Regulators
Parkway Bypass Regulator Station
Derry Rd.
Ninth Line
407
Tie-in New NPS 36 to Existing NPS 36 Parkway North
180 m
Gas Meter
Parkway West Gate Station
From Union Gas
Gas Meter
Union Gas Compressor
Existing NPS 36 Parkway North Pipeline
New NPS 36 Pipeline to Albion Station
TORONTO
MISSISSAUGA
BRAMPTON
410
401
407
427

Updated: 2013-02-12
EB-2012-0451
Exhibit A
Tab 3
Schedule 6
Attachment
Figure 1



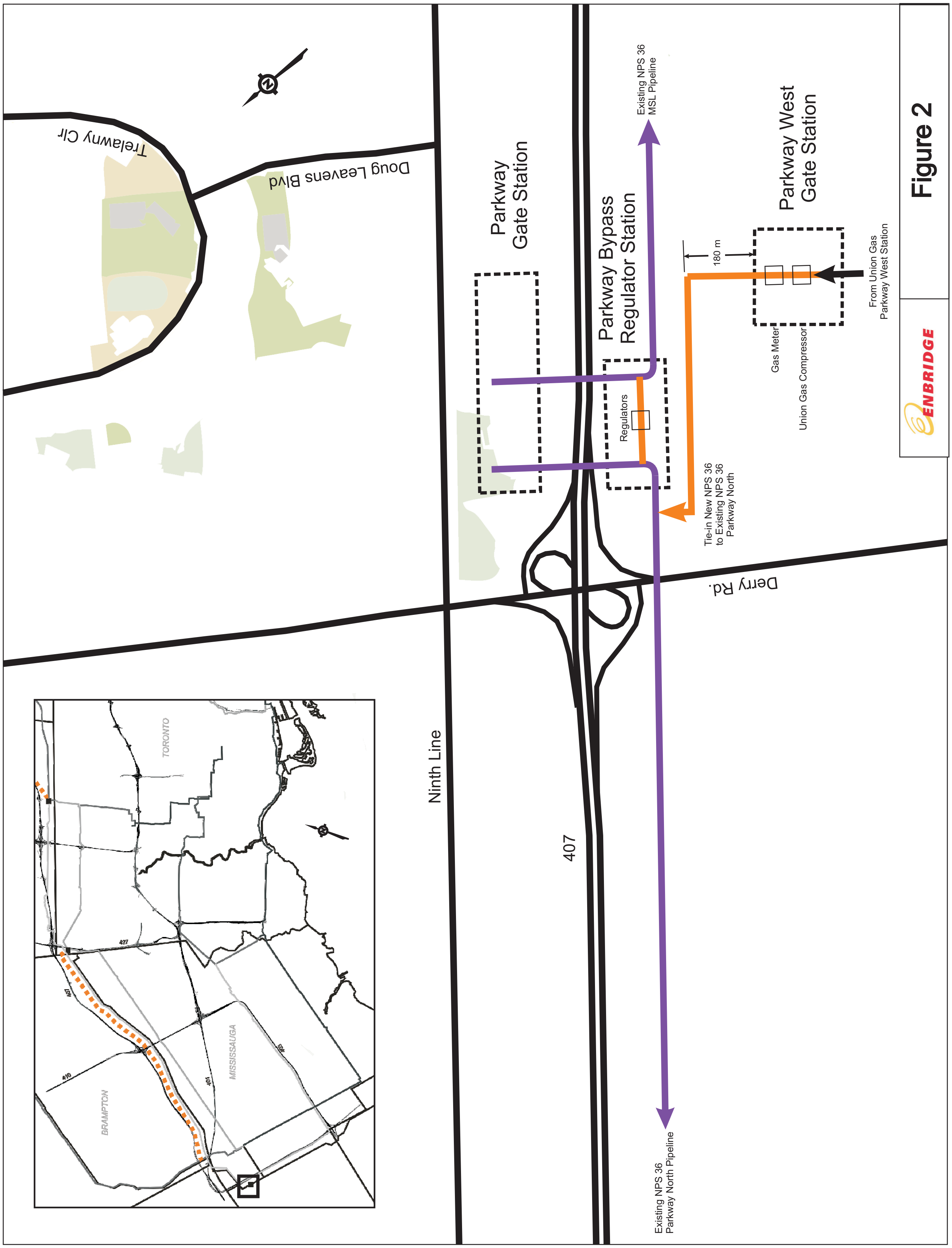


Figure 2
Trelawny Cir
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Parkway Gate Station
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Parkway West Gate Station
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Tie-in New NPS 36 to Existing NPS 36 Parkway North
Derry Rd.
Ninth Line
407
Existing NPS 36 Parkway North Pipeline
TORONTO
MISSISSAUGA
BRAMPTON

ALTERNATIVES

Note: Elements of this evidence have been updated through the submission of Exhibit A, Tab 3, Schedule 9 (filed on July 22, 2013).

1. The purpose of this evidence is to discuss other alternatives that were considered prior to proposing the GTA Project as it is currently described in this ~~application~~Application. Some of the alternatives explored can have some positive impact on ~~the Company's~~Enbridge's objectives. However, in order to achieve the full range of objectives, additional infrastructure was ultimately required. ~~The Company~~Enbridge spent considerable time examining alternatives where existing pipeline infrastructure could be utilized, both on the distribution system, and external to ~~the Company's~~Enbridge's system. Details on the examination of different options are described below.

~~1.~~

2. As mentioned in Exhibit A, Tab 3, Schedule 1, Enbridge had specific objectives that were considered while evaluating the alternatives. These objectives included:
   a. Meet customer growth requirements to 2025;
   b. Reduce operational risk by incorporating the capability of lowering the operating pressures on critical supply lines that are key to system reliability;
   c. Provide enhanced operational flexibility and improved connectivity between the western and eastern part of the GTA XHP system;
   d. Mitigate supply concentrations at gate stations; and,
   e. Displace less secure elements of its supply portfolio with more reliable supply, while reducing gas supply costs.

There are a number of alternatives that could be considered, alone, or in combination in order to meet the objectives.

Demand Side Management

3. ~~The Company~~Enbridge has a long history of providing Demand Side Management ("DSM") and conservation programs. These programs help consumers manage and lower their consumption of natural gas, benefiting consumers, the economy, and the

~~3.~~ environment. In examining a conservation approach to meet the objectives, there are three important points to note:

a. ~~The Company~~Enbridge currently implements a robust DSM program that has been reviewed and approved through a regulatory process. The currently planned DSM activities and conservation are already included in the forecast presented.

b. The issues with the distribution system are related to peak demand system loading, whereas conservation programs are typically targeted at lowering overall consumption. It is important to recognize the fundamental difference between these two items. Conservation programs will be focused on lowering total annual consumption in order to be economic over the life of the program. This can, at times, align with lowering of peak demand system loading. Examples include items such as higher equipment efficiency, better building envelopes, and higher efficiency heat recovery ventilators. However, some conservation programs can actually accentuate the system peak demand, particularly at hourly intervals. System controls, such as set back thermostats, typically lower the temperature differential from the inside to the outside of the building, thus lowering the heating requirement during the period of setback. However, when employed on a large scale, the system impact on peak loads can be significant when a large proportion of customer equipment turns on to re-heat the buildings at approximately the same time. Nighttime set back controls, while economic for consumers, increases peak loading as the system has lost the diversity factor from that group of customers. Other examples are instantaneous water heating, where the storage tank losses are eliminated. This benefits the consumer; however, the system diversity is lost during periods of high demand which creates a larger peak demand on the system. This is demonstrated in Exhibit A, Tab 3, Schedule 5, Figure 5.

c. Conservation efforts, while a worthy and important goal, cannot be expected to replace the capacity within the system due to the lowering of pressures on large diameter, higher pressure lines, or create the needed diversity in the supply chain.

Compression within the Distribution System

4. Consideration was given to add compression at key locations, such as Station B for example, to alleviate the potential of falling below minimum system pressure requirements. In order to accomplish the same supply and reliability objectives as the GTA Project scope proposed, adding compression would be required at numerous locations. Finding a suitable location for a compression facility is problematic in an urban setting. This is particularly true if consideration is given to Loss of Critical Unit ("LCU") requirements and design standards on separation distances between compression units. Multiple units, and appropriate separation between units, are required to achieve comparable operational reliability as a reinforcement pipeline. In addition, the distribution system currently does not use compression in the distribution system. This would require several new business and labour processes for the Company in this geographic area. Therefore, compression was considered to be a less favourable alternative for the system.

Curtailment of Existing Firm Customers

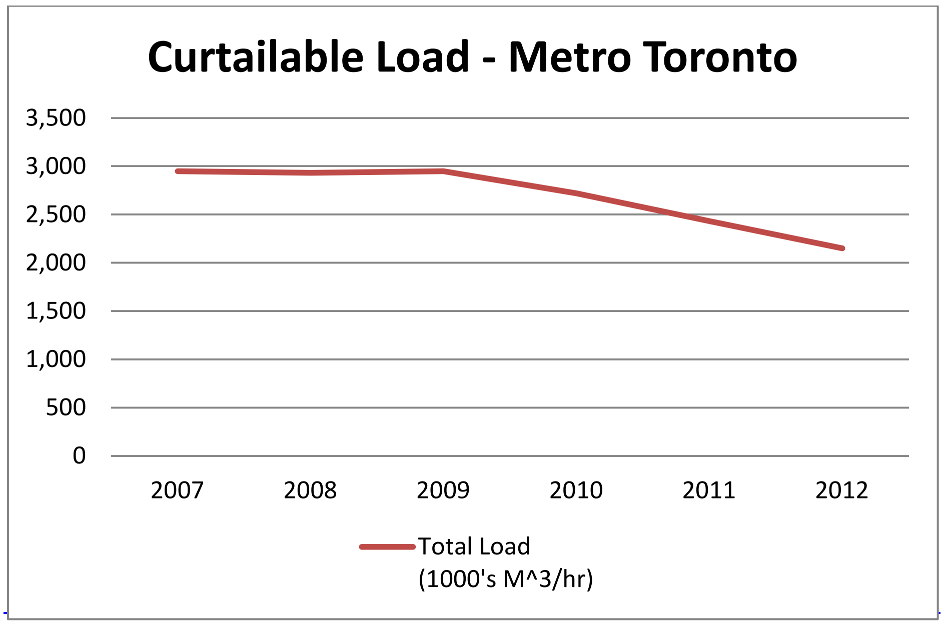
5. ~~The Company~~Enbridge could approach existing firm customers to determine their willingness to switch to non-firm contracts. The intent would be to reduce the system's present firm capacity requirements in order to support further customer growth and remove the need for reinforcement. This was determined to be an impractical approach since it would yield minimal additional capacity without the benefit of long term capacity availability. It was also identified as a lengthy process

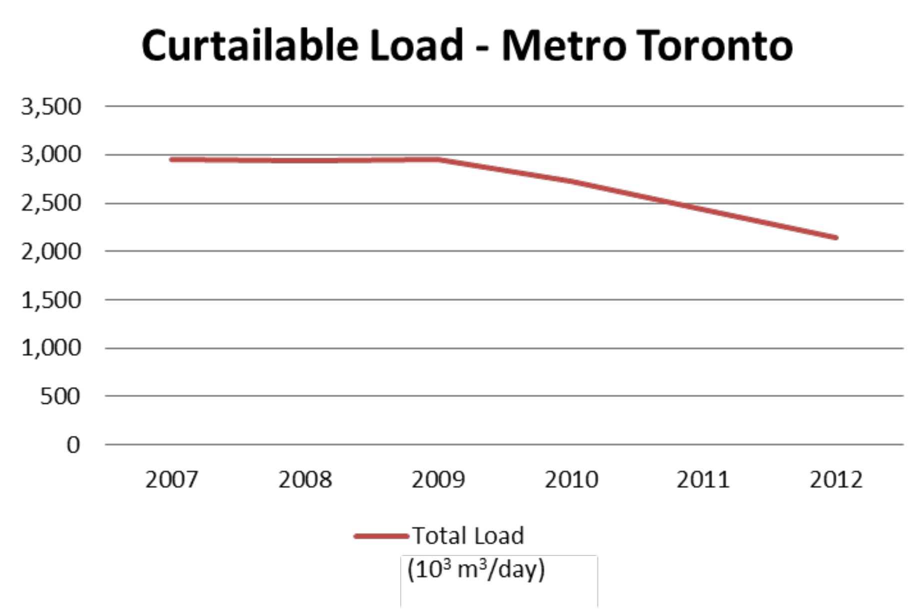
with minimal success. ~~The Company~~Enbridge currently offers interruptible service. Those customers that find

~~5.~~ it a practical and economic alternative already contract for interruptible service. Finally, this runs counter to the trend in curtailment over the last five years, as shown in Figure 1.

Figure 1: Historical Curtailable Load within Metro Toronto

/u





Liquefied Natural Gas ("LNG")

6. LNG was considered to provide the additional peaking capacity required for the system, offsetting the need for other infrastructure. Although benefits could be achieved through this type of facility, obstacles to finding an appropriate site area are significant. Given the current location of minimum system pressure at Station B, the site would need to be in close proximity to this area in order to minimize the need for other infrastructure. Location of an LNG facility would require significant setbacks, particularly one that could handle the large demand of the GTA. If a facility was sited outside of the GTA, a corresponding pipeline with associated takeaway capacity would then be required to connect to the GTA XHP grid as a

~~6.~~ supply source. Finally the other distribution system objectives would still have to be addressed. The total combined costs were expected to be more costly in comparison to other alternatives considered.

Procurement of Transport Services

7. Procurement of transmission services was also considered. As noted previously in Exhibit A, Tab 3, Schedule 2, the Company has previously delayed building infrastructure internal to the distribution system through consulting with upstream transport providers and procurement of transport services. Historically, this has been procurement of services that flow through the Parkway to Maple portion of the TransCanada system, in order to move firm transport volumes further east prior to entry into the GTA distribution system. This has been a fundamental business decision for ~~the Company~~Enbridge over a number of years. The decision to "buy" versus "build" is a common decision for many companies, in many different industries. What makes the natural gas transport/distribution business different is the very long life and significant upfront costs associated with decisions to build new infrastructure. Ultimately, the costs of new infrastructure are born by consumers, whether it is built by a transport company or a distribution company, and therefore, any new infrastructure requires careful consideration. ~~The Company~~Enbridge invested a significant amount of time and effort in considering both internal and external alternatives, or comparing "buy" versus "build" alternatives, as detailed below.

8. In order to procure firm, short haul capacity, infrastructure must be available. Currently, there is a constraint between Parkway and Maple, as demonstrated by the recent open seasons and new builds by TransCanada along this path. Significant new capacity along this path would require new infrastructure to be built. As noted above, the cost of the infrastructure is ultimately born by consumers,

regardless of whether the infrastructure is built for transmission or distribution. The GTA XHP grid is also constrained at Parkway, as it cannot flow more gas from west to east through the existing infrastructure. The Parkway constraint is an important consideration for any new infrastructure requirement.

Distribution System Expansion

9. In examining the distribution system constraint, it should be noted that the Company had planned Parkway Phase 3 for many years. This segment of pipeline would extend the current NPS 36 Parkway North line from Keele/CNR Station, along the utility corridor known as the Parkway Belt West Plan corridor to connect with the NPS 30 Don Valley line. This system reinforcement has been continuously deferred through purchase of transport services from Parkway to the CDA, ultimately brought into the GTA system at the Victoria Square Gate Station. This section of pipeline would alleviate the west-east constraint on the XHP grid, and is also critical to allow for the reduction in the operating pressure on the NPS 26 line.

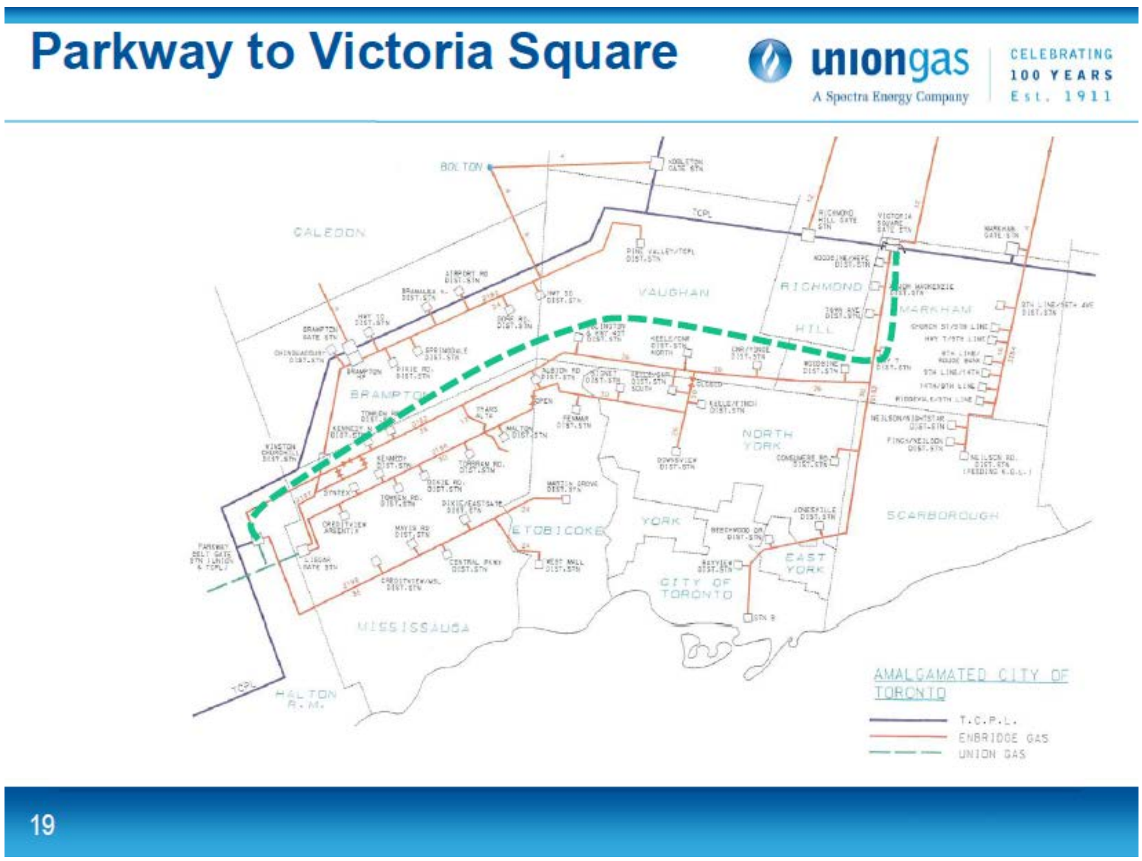
~~10.~~ 10. The Company had also planned an extension of the NPS 36 line that parallels the NPS 30 Don Valley line, extending the line north from Sheppard Avenue. The purpose of this north–south section pipeline is to allow for greater flow and higher pressure to be maintained at the point of minimum system pressure.

11. Parkway Phase 3 and the NPS 36 Don Valley line extension are part of the facilities proposed in this Application and, in combination, are referred to as Segment B. Segment B will complete a continuous NPS 36 line from Parkway Gate Station to the NPS 30 Don Valley line and as far south as Eglinton Avenue. In conjunction with the existing NPS 30 Don Valley line, this would create a large diameter linkage in the XHP system, increasing the flexibility of the entire XHP grid. For this reason, Segment B is considered to be a core distribution requirement and would be

required under any alternative. Although Segment B creates a large diameter linkage between Victoria Square and Parkway Gate Stations, allowing the two stations to diversify one another, this alone is inadequate to meet all the objectives. The distances and loads served are too large for this to be viable in even moderate winter conditions. In addition, Segment B would not diversify the over-dependence on the two largest gate stations within the system. This could only be accomplished with the addition of a new supply source, requiring consultation with upstream suppliers.

12. ~~The Company~~Enbridge consulted extensively to ensure it had examined all viable alternatives. In consulting with Union Gas as far back as early 2011, an option was presented to alleviate the Parkway to Maple constraint through construction of a transmission line through the ~~Company's~~Enbridge's franchise area. The proposed line is shown in Figure 2 below.

Figure 2[1]: Union Gas Parkway to Victoria Square Proposal



13. This alternative has several attractive features, most notably:
    1. Relieving the Parkway to Maple constraint; and,
    2. Allowing for one or more gate stations to be placed along the path diversifying supply sources for distribution.

[1] Source: EB-2011-0210, J.B-1-7-8 Attachment 12, Slide 19

~~14.~~ 14. However, the total cost is an issue. As previously noted, all costs, whether they are transmission or distribution, are ultimately paid by customers. This solution was new infrastructure and did not optimize the use of existing assets, in the transmission systems or the distribution system.

15. Continued discussion on how to meet both the transmission and distribution needs at Parkway ultimately led to the concept of a joint use pipeline. A joint use pipeline would relieve the Parkway constraint on both the distribution system and the transmission system. This would allow for the shortest overall distance being constructed and maximize the use of the existing infrastructure. Also, for a significant length of the new pipelines, it would allow for economies of scale through the joint use of a section. This concept also has benefits for the community, as there would only be construction of one pipeline, versus two if the distribution and transmission needs were considered in isolation. This was the concept behind Union's Parkway Expansion Project[2] where Union hosted an open season for capacity between Parkway and Maple. This service would be facilitated through a joint use pipeline (Segment A), and through another to be constructed pipeline from Albion Road Station to Maple. Although the Open Season for Union's Parkway Expansion Project was not successful, the analytical work that went into it identified the importance of the path of transmission expansion. A path from Parkway to Albion to Maple allowed for the joint use of facilities. This joint use arrangement has two primary benefits:

    1. Economies of scale; and,
    2. Less disruption from construction for the community.

[2] Reference: EB-2011-0210, J.B-1-7-8 Attachment 13

16. Significant time and effort went into looking at other alternatives for meeting the stated objectives. There are many options for routes and/or transport arrangements that could achieve the objectives in a large system such as the GTA. For simplicity of presentation, these variants are grouped together into thematic options in the following paragraphs.

Northern Perimeter Capacity Purchase

17. The Northern Perimeter Capacity Purchase option would involve increasing take away capacity off TransCanada along the northern perimeter of the GTA east of Maple. It also included reinforcement of the distribution system to maintain minimum pressure at Station B during peak conditions.

18. Under this alternative, the majority of gas supply required for the new demand growth would be delivered through Victoria Square Gate Station, which is already the second largest supply point within the system. New supply would be sourced from the WCSB, due to the current restriction in short haul capacity. From an economic perspective, the most appropriate service would be 3-month STFT service. This service would best match the seasonal peaking nature of the demand growth on the system as described in Exhibit A, Tab 3, Schedule 5.

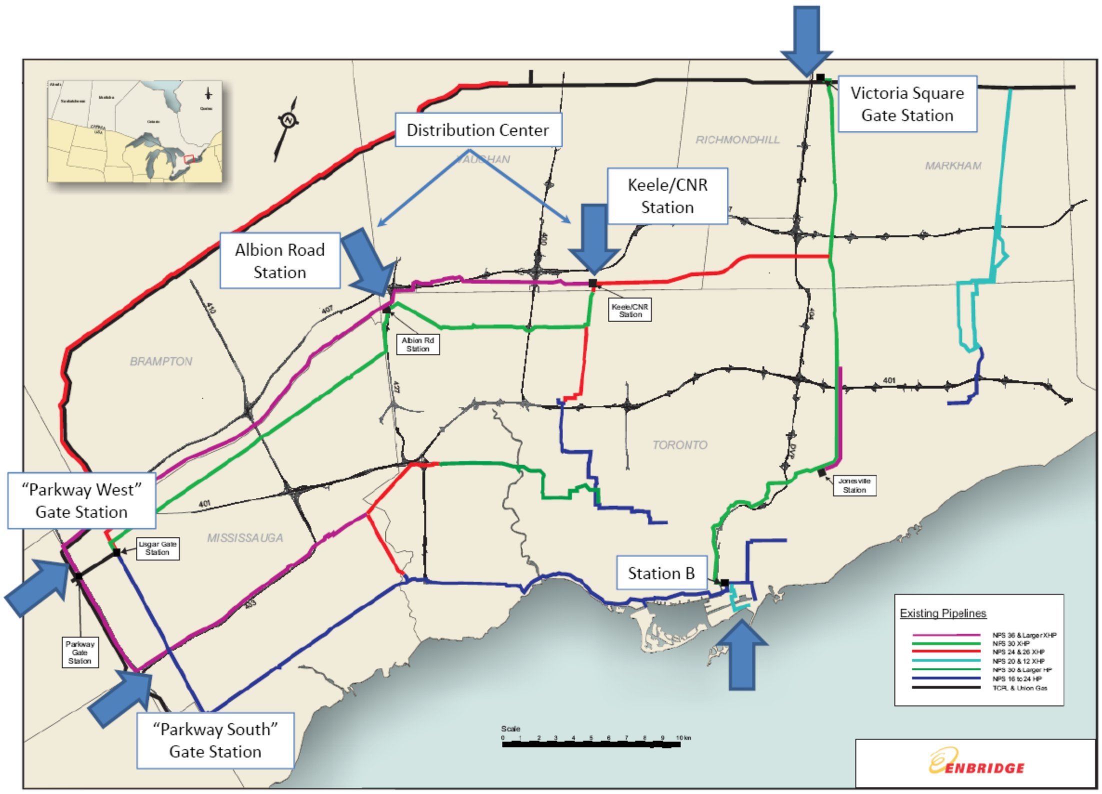
19. In order to meet minimum system pressure at Station B, a new NPS 36 pipeline from Victoria Square Gate Station to a connection with the existing NPS 30 Don Valley line and the NPS 36 line at Eglinton Avenue would be required in order for more supply to be brought into the XHP system. This line would need to be connected to the existing Parkway North NPS 36 line at Keele/CNR Station to eliminate the restriction caused by the NPS 26 line. This variant is depicted in Attachment, Figure 1 and is essentially Segment B proposed in this application with the addition of a north-south line connecting Victoria Square and Buttonville

Stations.

20. This alternative would not meet all of the objectives defined. It would not diversify the entry points to the distribution system and it would increase the dependence of the supply portfolio on less reliable forms of transport, such as STFT. As described in Exhibit A, Tab 3, Schedule 5, increased reliance on a non-renewable transportation service such as STFT is not considered prudent, given the potential of reduced capacity on the TransCanada Mainline, declines in WCSB supply and increases in U.S. North East supply. To meet all the objectives, diversification of entry points and displacement of STFT with short haul supply would require a new gate station in the vicinity of Victoria Square Gate Station, capable of serving as a back-up to either Parkway or Victoria Square Gate Stations, and an expansion on TransCanada's system from Parkway to Maple facilitating a new short haul path.

21. Variants of this alternative envision a different north-south lateral from a new gate station on the TransCanada Mainline. Mainline points east of Maple that facilitate a connection either into Albion or Keele/CNR Stations, rather than from Victoria Square Gate Station to Buttonville Station, all in combination with Segment B would be near equivalents. Figure 3 depicts these entry points. All variants require new infrastructure in order to expand capacity from Parkway to Maple, unless greater use of long haul STFT is contemplated.

Figure 3: New Entry Points Considered



Southern Perimeter East West Expansion

22. As described in Exhibit A, Tab 3, Schedule 3, reinforcement options to accommodate customer growth must ensure that minimum inlet pressure at Station B is met by the 2015/2016 heating season. Station B is one of the furthest points from any upstream supply which makes it more challenging to maintain minimum pressures as peak day demand increases. The Southern Perimeter route would originate at the west end of the GTA System, south of the existing Parkway Gate Station and terminate at Station B.

23. Delivering supply to Station B, across the southern perimeter of the GTA, has particular space and cost constraints owing to the intensity of development and use

of traffic corridors through the south of the GTA. The necessary takeaway capacity would need to consider pressure elevating existing infrastructure, building new infrastructure, a combination thereof, or on a new, more southern, route through Lake Ontario.

24. First, a pressure elevation of the existing NPS 20 HP Lake Shore line was not considered due to its prior pressure reduction.

25. Second, consideration was given to full and partial replacement, at both NPS 30 and NPS 36 diameter pipe sizes, and integrating the new line into the XHP network at various pressures. This alternative was considered to be unfavourable due to the higher cost compared to other alternatives and socio-economic challenges with construction on the highly-travelled and utility-congested road along Lake Shore Boulevard West.

~~26.~~ Third, an option was considered for reinforcement through the elevation of the NPS 36 MSL line and installing a parallel NPS 24 or NPS 30 line to the existing NPS 24 XHP line that terminates at West Mall Station. From West Mall Station, the NPS 20 HP Lake Shore line would be replaced with a new NPS 30 pipeline, terminating at Station B. This alternative would complete an XHP loop and provide significantly increased reliability of the XHP grid. However, the associated costs for construction were estimated to be high compared to other alternatives. In addition, the disruption to the community for the type of urban construction that would be required was considered to be problematic. This solution did not fulfill the objective

26. to reduce the vulnerabilities in the supply chain, nor did it assist in alleviating the restriction across the NPS 26 Parkway North line.

27. Fourth, and lastly, the Company considered a new pipeline routed through Lake Ontario from "Parkway South" to Station B. A pipeline with this route had several attractions for reinforcement of the GTA system. It would allow new supply to be delivered directly into Station B. It would also avoid difficulties with urban construction (including tight urban working spaces, traffic management, and conflicts with the congested underground utility infrastructure). This alternative would require both a pressure elevation of the existing NPS 36 MSL line and a new NPS 30 pipeline routed through Lake Ontario. However, evaluation of the new pipeline routes through Lake Ontario concluded that magnitudes and uncertainties in costs and timing overruns were unacceptable. It also does not provide the advantage of looping along existing corridors which provides greater flexibility in the longer term.

Central Access with East West Expansion and North South Expansion

28. This alternative included a new gate station in the vicinity of the existing Parkway Station (Parkway West), combined with take away capacity to a central point in the distribution system. Consideration was given to whether the central point would be defined as the load center or the central point for takeaway capability. The latter option was viewed as more desirable as it would meet system reliability objectives, while maximizing the use of the existing infrastructure, and decreasing any new infrastructure requirements for future growth.

29. The optimal central point for take away capacity was identified as Albion Road Station or Keele/CNR Station. This is due to their central location and ability to tie into existing infrastructure and distribute gas in all directions. This would be

advantageous under both peak and adverse conditions to be able to move gas to the areas within the distribution network with greatest demand.

30. A route from "Parkway West" Gate Station to Albion Road Station could parallel the existing NPS 36 XHP Parkway North line constructed through Parkway Phase 1 (described in Exhibit A, Tab 3, Schedule 2) and could be mainly located within the same designated Parkway Belt utility corridor.

31. The Parkway West Gate ~~station~~Station would also serve to diversify the existing Parkway Gate Station supply, via a short ~~180~~315 metre tie-in pipeline segment, allowing the supply to be sourced for the system from both facilities. In addition, should a situation arise at either site, such as an integrity or maintenance requirement, the other site would be available to ensure a continuous supply for customers.

32. "Parkway West" Gate Station, a new NPS 36 XHP line paralleling the existing NPS 36 XHP Parkway North line (along with the ~~180~~315 metre tie-in between the two lines), and associated station expansion to Albion Road Station and upgrade to the Parkway Bypass, were later labeled as Segment A.

33. Although the benefits of this route were extensive, they were limited by the ability to move gas further east and south to the point of minimum system pressure at Station B. An additional west-east pipeline segment would be required to alleviate the restriction in the NPS 26 XHP Parkway North line and a north-south segment to facilitate gas supply delivery to Station B to meet peak day demand requirements. The two pipeline spans would also allow for increased utilization of gas supply benefits acquired through new "Parkway West" interconnection.

34. As mentioned in Exhibit A, Tab 3, Schedule 2, the need for the pipeline NPS 36 XHP segment from Keele/CNR Station to the NPS 30 Don Valley line was originally identified as Parkway Phase 3. This project was initially planned in the early 1990's, then revisited in the early 2000's, but postponed until now since the additional west to east gas transportation volumes could be delivered by TransCanada under short haul contracts. The construction of this pipeline route is still deemed to be required to alleviate the west to east restriction in the XHP grid. This section strengthens the connectivity between the two major entry points into the system (Victoria Square and Parkway Gate Stations), allowing for one source to offset potential shortfalls from the others. This section of pipeline also allows for increased takeaway capacity from Parkway Gate Station for distribution to the eastern portion of the GTA.

35. The north-south segment was still required to add the capacity needed to bring gas supplies towards the downtown Toronto core to meet the minimum pressure requirements at Station B. Previous long range planning for system load growth had identified the northward extension of the NPS 36 XHP pipeline in the Buttonville corridor from Sheppard Avenue East to just north of Highway 407 as the best alternative for meeting the replacement capacity requirements for PEC.

36. The new NPS 36 XHP east-west and north-south segments described above, the new "Buttonville Station", and the associated station modifications and expansions to both Keele/CNR Station and Jonesville Station, were later labeled as Segment B.

37. The Central Access options showed greater supply chain benefits than any of the Northern Perimeter Capacity Purchase or Southern Perimeter alternatives. In addition, it offered constructability and right of way benefits relative to the Southern Perimeter options considered and as a result was carried forward for Environmental

Review.

~~Perimeter options considered and as a result was carried forward for Environmental Review.~~

Central Access Variations Considered

38. ~~The Company~~Enbridge considered other variations as part of the project development process. Most notably, particular consideration was given to other existing infrastructure, and how it could potentially be utilized to meet ~~the Company~~Enbridge's objectives. There is a significant amount of existing gas transportation infrastructure in the area around the Parkway facility. It is not only a major gate station, but also a major compression, transmission, and gas interchange point. ~~The Company~~Enbridge noted that TransCanada currently has a NPS 36 and NPS 42 transmission system that parallels the proposed routing of Segment A up until these pipelines cross Highway 407 and continue north to TransCanada's Maple compressor facility. ~~The Company~~Enbridge approached TransCanada and suggested a new delivery point be considered at or near the point where the existing lines cross Highway 407. This would reduce the length of Enbridge's proposed Segment A by approximately 5 km. Details of discussions are described in more detail in Exhibit A, Tab 3, Schedule 1, ~~paragraph 29~~page 10. Overall, this would be a variation in the project scope and does not significantly alter the purpose, need or timing. The two potential initiation ~~point proposed in this Application (~~points for the Segment A pipeline, interconnecting with Union Gas~~) and the alternate initiation point (intersecting with~~ or TransCanada~~)~~ are shown in Figure 4. Enbridge had initially applied for the connection to Union Gas and has amended the Application via Update No.1 to interconnect with TransCanada. The primary difference ~~would be a shortening of~~is the Segment A~~,~~ pipeline is approximately 5 km shorter and ~~utilization of~~utilizes TransCanada's existing facilities~~.~~ between Parkway and the Bram West Interconnect.

~~The Company~~

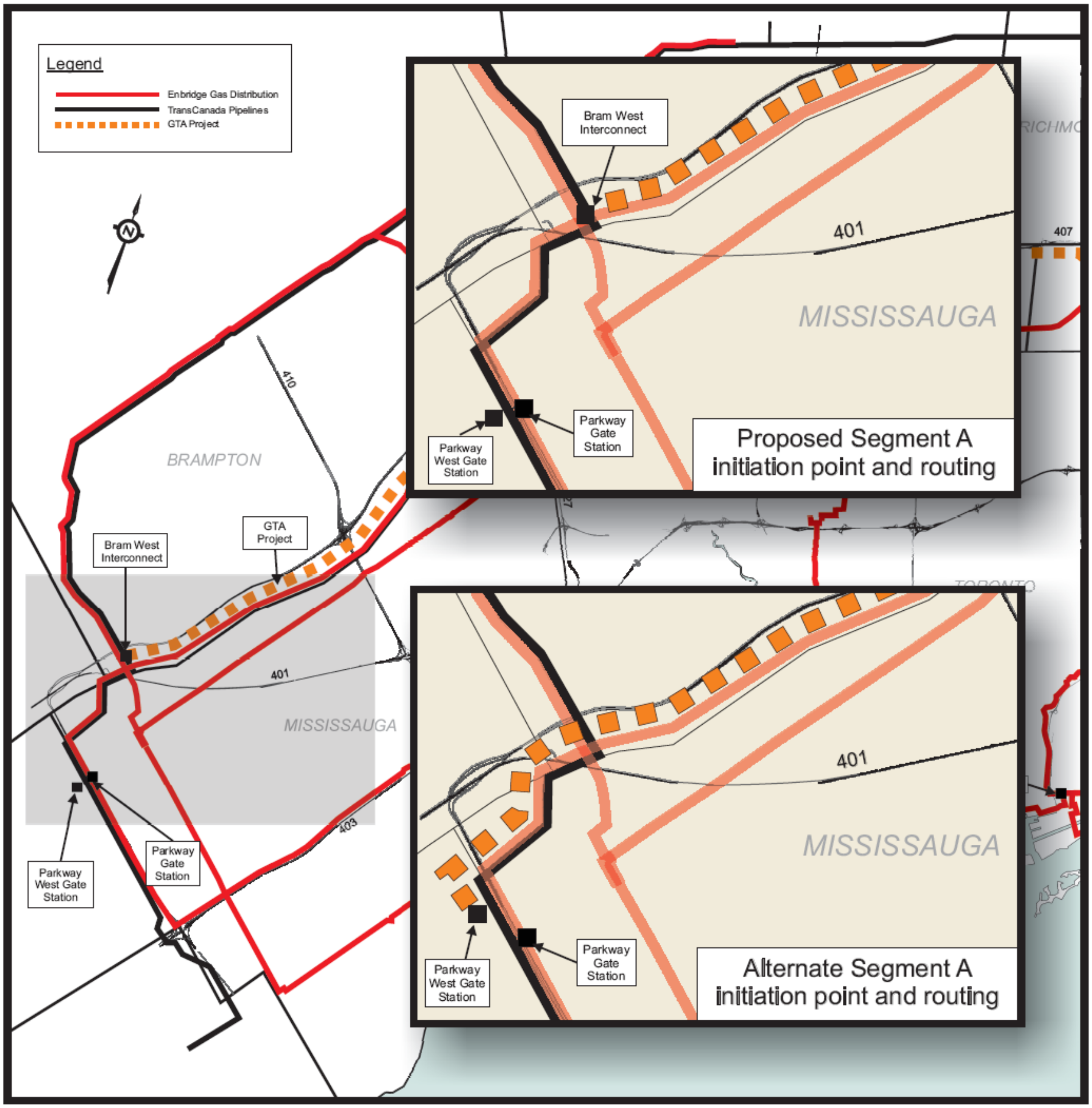
39. Enbridge has agreed ~~to continue to work~~ with TransCanada to ~~consider this variant to its GTA Project scope and is willing to incorporate it into~~shared usage of Segment A. In order to accommodate the ~~final scope of the GTA Project. However, any~~combined volumes of the two companies, the Segment A pipeline will be NPS 42. As described in Exhibit A, Schedule 3, Section 6, some of the originally proposed facilities locations would change due to the combination of

new interconnection point and the shared usage. This arrangement with TransCanada ~~would be~~is subject to NEB approval. ~~Consequently, this application forms the minimum requirements to meet the purpose, need,~~

~~39.~~40. The new starting point for Segment A and ~~timing of the project.~~ the upsizing and shared usage of the pipeline will potentially eliminate the need for duplicative pipelines/facilities resulting in less environmental and community impacts

~~40.~~41. ~~The Company~~Enbridge expects to continue to work with TransCanada to formalize details ~~that will be required for an amendment to this application.~~with respect to the tolling impacts of utilizing TransCanada's Mainline from Parkway to Bram West Interconnect, and the cost implications of the shorter Segment A, increased pipe size, and shared usage. Once these details are completed ~~the Company~~Enbridge will update the Board at that time. The updates are currently expected to be submitted in late March 2013.

Figure 4: Map of the Variation on the Initiation Point with Union Gas or TransCanada



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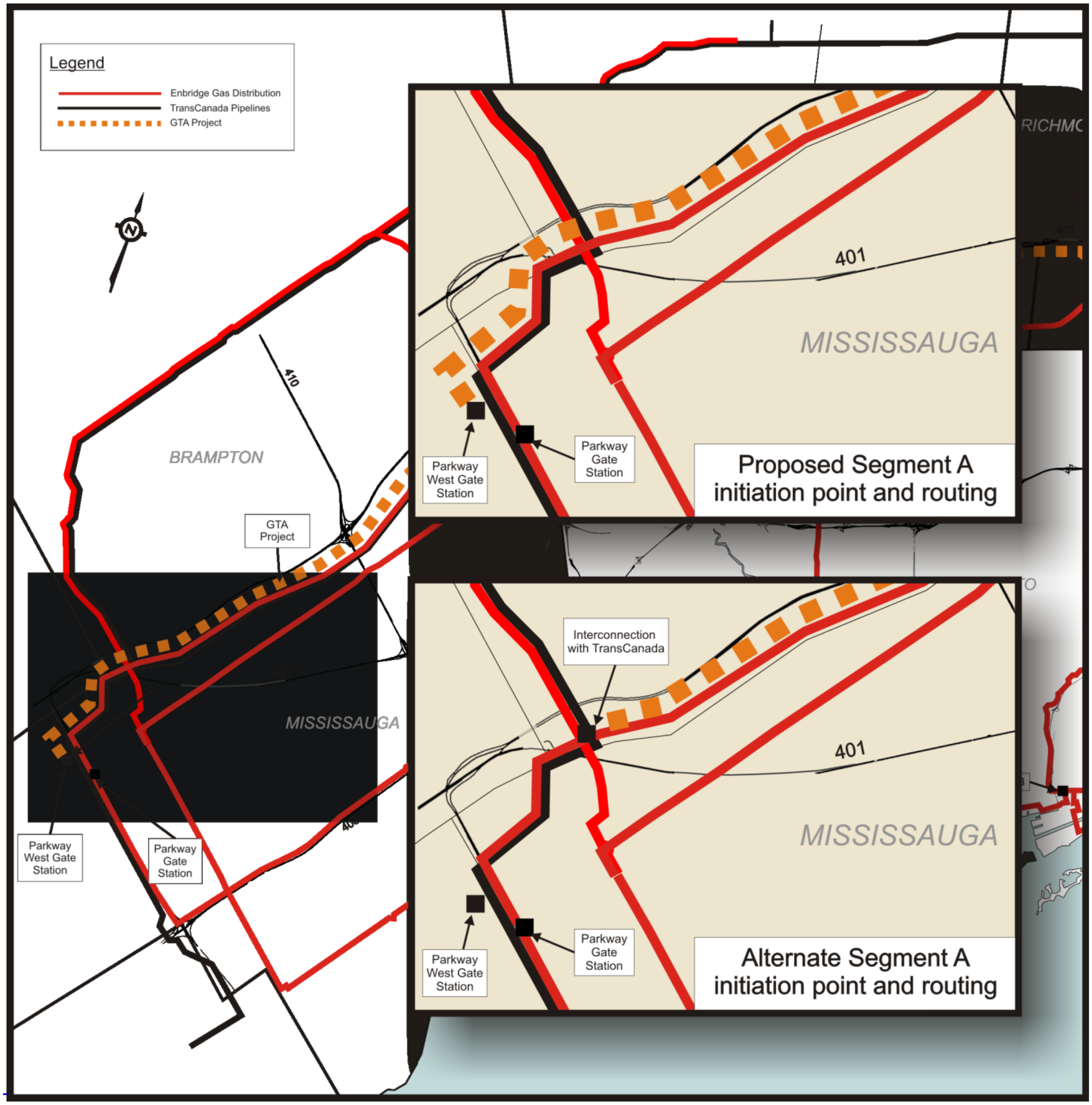
EB-2012-0451
Exhibit A
Tab 3
Schedule 7
Page 26 of 26
Plus Attachment



TIMING

Note: Elements of this evidence have been updated through the submission of Exhibit A, Tab 3, Schedule 9 (filed on July 22, 2013).

1. The purpose of this evidence is to describe the timing requirements to construct and commission the proposed facilities. ~~The Company~~Enbridge is seeking a decision by the Ontario Energy Board ~~prior to August 1,~~(the "Board") in September 2013 to proceed with the project design, planning, and procurement in order to ~~start construction by the proposed date and to~~ meet the ~~objectives described in Exhibit A, Tab 3, Schedule 1.~~

in-service requirements of November 2015 for these facilities.

~~System models demonstrate that the pressure will drop below minimum system requirements at Station B in the 2015/2016 heating season on a peak demand day (41 DD). Segment B fulfills the system's need to meet customer growth and to enhance the flexibility and diversity of the XHP system on the eastern side of the GTA. Given the criticality of the minimum system pressure at Station B, and the potential impacts on the supply chain that the proposed facilities mitigate, the Company is of the opinion that the construction should commence so that~~

~~Segment B can be in service for January 2015, while Segment A could be placed in service prior to November 1st, 2015. As detailed in Exhibit C, Tab 2, Schedule 2, Proposed Construction Schedule, common construction scheduling between both segments allows more efficient use of contracted resources, leads to significantly~~

2. The in-service requirements are based on the following three factors that impact the 2015/2016 heating season: (1) inability to attach customers and meet minimum pressure requirements in the GTA Project Influence Area on peak day, (2) reliance on non-renewable transportation services that may be impacted in the 2015/2016 heating season[1], and (3) service requests from TransCanada's shippers for November 1, 2015. Distribution system requirements for growth and reliability are described at Exhibit A, Tab 3, Schedules 4 and 6, respectively. Gas

[1] Based on TransCanada's two recent public announcements: (1) Canadian Mainline Existing Capacity Open Season and (2) The Energy East Pipeline Open Season, which are described in Exhibit A, Tab 3, Schedule 5.

supply reliability concerns and gas supply benefits are described at Exhibit A, Tab 3, Schedule 5.

Project Schedule

~~2.~~ The schedule and~~lower costs, and is the basis for the cost estimate in this application.~~ ~~Additionally, as noted below, there are specific seasonal windows for certain elements of the construction required. Due to these restrictions, the impact of moving the schedule outward would in effect require a full year change in the schedule or a significant change in cost. As a result, the Company plans to commence construction of the proposed facilities in August 2014 to be in-service by Winter 2015 to ensure reliable service.~~

~~3. The~~ total project costs are predicated on the successful completion of the next stage of project requirements. This includes detailed design engineering, the receipt of permits, the procurement of the necessary material, labour, and equipment, and the proposed construction schedule. A high level summary of the proposed project schedule ~~is below~~follows, which is also provided as a Gantt Chart in Figure 1 attached to this schedule. The proposed construction schedule is described in Exhibit C, Tab 2, Schedule 2.

	Start	End
Regulatory Proceedings	December 2012	~~August~~September 2013 (Expected)
"Pull Forward" Engineering[2] ("PFE")	In Progress	~~August~~September 2013
Permits	In Progress	~~July~~October 2014
Environmental	In Progress	~~March~~September 2016
Detailed Engineering Design ("DED")	~~August~~September 2013	~~July~~November 2014
Procurement	~~August~~September 2013	March ~~2015~~2016
Construction (Segment A&B)	~~August~~December 2014	~~April~~September 2015
Testing and Commissioning	September 2015	October 2015

3. As mentioned in Exhibit C, Tab 2, Schedule 2, the construction schedule is driven by an extensive Horizontal Directional Drilling ("HDD") program which will be performed by an HDD contractor working in parallel to the mainline contractor. Common construction scheduling between both segments allows more efficient use of contracted resources, leads to lower costs, and is the basis for the cost estimate in this application.

Critical Path Dependencies

Detailed Engineering Design ("DED")

[2] "Pull Forward" Engineering is engineering work advanced from the "Detailed Engineering Design" phase. This work is advanced during the regulatory ~~proceedings~~proceeding to mitigate risks and costs associated with delays that may influence the construction schedule.

4. The Company is taking steps to mitigate risks with construction delays to meet the required in-service dates and to also mitigate project costs and overruns. These steps include the advancement of work to a Pull Forward Engineering ("PFE") phase that would otherwise be performed in the DED phase. The PFE is necessary for ~~the environmental work, permit applications, and~~ procurement planning~~.~~ and permit applications. Examples of this work are described below.

Procurement

5. The lead time to procure specialized HDD services to install large diameter pipe is expected to take more than one year. It is expected that there will be high demand for this specialized skill and equipment at the time of the proposed construction schedule as a result of other pipeline projects across Canada and the U.S. HDD design work must be completed in advance of HDD procurement and is therefore included in the PFE phase. The lead time to procure pipe and special fittings is also expected to take more than one year given the size and availability.

Permitting

~~5.~~6. The lead time for approximately ~~315~~300 permit requirements is expected to vary from ten days to up to two years. Permits with the longer lead times, up to two years, are from the Ministry of Natural Resources for watercourse crossings with species at risk[3]. Other work requiring permits, such as tree pruning, can only be performed in specific seasonal windows. This requires the permits to be obtained ~~between~~up to one ~~to two seasons~~season in advance of construction in addition to

[3] Redside Dace (fish species) habitat was identified at three watercourses. The Redside Dace is protected under the provincial legislation, the Endangered Species Act (Ontario) ("OESA"). An OESA Permit typically takes more than 1.5 years to obtain.

the estimated one year required to apply and obtain the necessary permits. Other permits, such as hydrostatic water discharge permits, and some land requirements are also expected to take more than one year. The majority of the permit application process will commence following project approval; however, there is a potential for construction start delays due to permitting delays. Permits with longer lead times will commence earlier than project approval due to time sensitivities with ~~the~~ both the permit requirements and project need.

Project Changes and Schedule Impact

7. The proposed changes in Update No. 1, as described in Exhibit A, Tab 2, Schedule 4, required the Company to revisit the project cost estimate, schedule, and in-service dates. In particular, upsizing the Segment A pipeline from NPS 36 to NPS 42 requires incremental time in the engineering design and procurement phases. In addition, the lead time ~~to procure specialized Horizontal Directional Drill ("HDD") services to install large diameter pipe~~for materials for the NPS 42 design is ~~expected to take more~~several months longer than ~~one year. It~~the lead time for materials for the NPS 36 design. This is ~~expected that there will be high demand for this specialized skill and equipment at the time~~a significant driver in the schedule to meet the required in-service date of ~~the~~
November 1, 2015.

8. The revised design and procurement requirements shifted the originally proposed construction schedule ~~as~~, which conflicted with construction limitations in the

winter months around the NPS 30 Don Valley line[4]. Pressures would have to be lowered to facilitate work in proximity to this line which may compromise its ability to adequately serve the City of Toronto in peak conditions as described in Exhibit A, Tab 3, Schedule 3. The increased project and operational risks were not considered to be tolerable to proceed as formerly presented.

9. As a result ~~of other pipeline projects across Canada and the U.S. HDD design work must be completed in~~ , it was determined that it is no longer feasible to start construction as originally proposed in August 2014 and target Segment A and B in-service dates in April 2015 and December 2014, respectively.

~~6.~~10. The Company is continuing to advance ~~of HDD procurement and is therefore included in~~ work on the critical path to mitigate risks with the project schedule. Critical path items can be advanced from the PFE phase~~; however, procurement contracts will commence following Board approval~~ for the first month beyond the currently contemplated timeline, however in subsequent months, working exclusively on critical path items would compromise the current cost and schedule estimates. The advancement of critical path work would be approximately $0.5 million to $1.0 million in the first month, which increases two to three times from this amount for the second month. Beyond the second month, costs would be expected to escalate significantly due to the ~~likelihood of unfavourable cancellation clauses.~~
requirement to potentially incur cancellations charges on long lead time items and critical resources, such as HDD and mainline contractors.

[4] Although the construction of Segment B will begin in January 2015, any work around the NPS 30 Don Valley line will be performed in the spring and summer months due to winter construction limitations in proximity to this line.

Summary

~~7.~~11. In summary, in order to have Segment A and B in-~~-~~service prior to ~~January~~November 2015, construction must begin no later than ~~August~~December 2014~~ and~~. Since the design, permitting, and procurement process will take more than one year to complete~~.~~, DED over and above the PFE must commence in October 2013. The Company is therefore seeking a decision from the Board no later than ~~August 2013.~~
September 2013. A Board decision beyond September 2013 may have one of the following impacts:

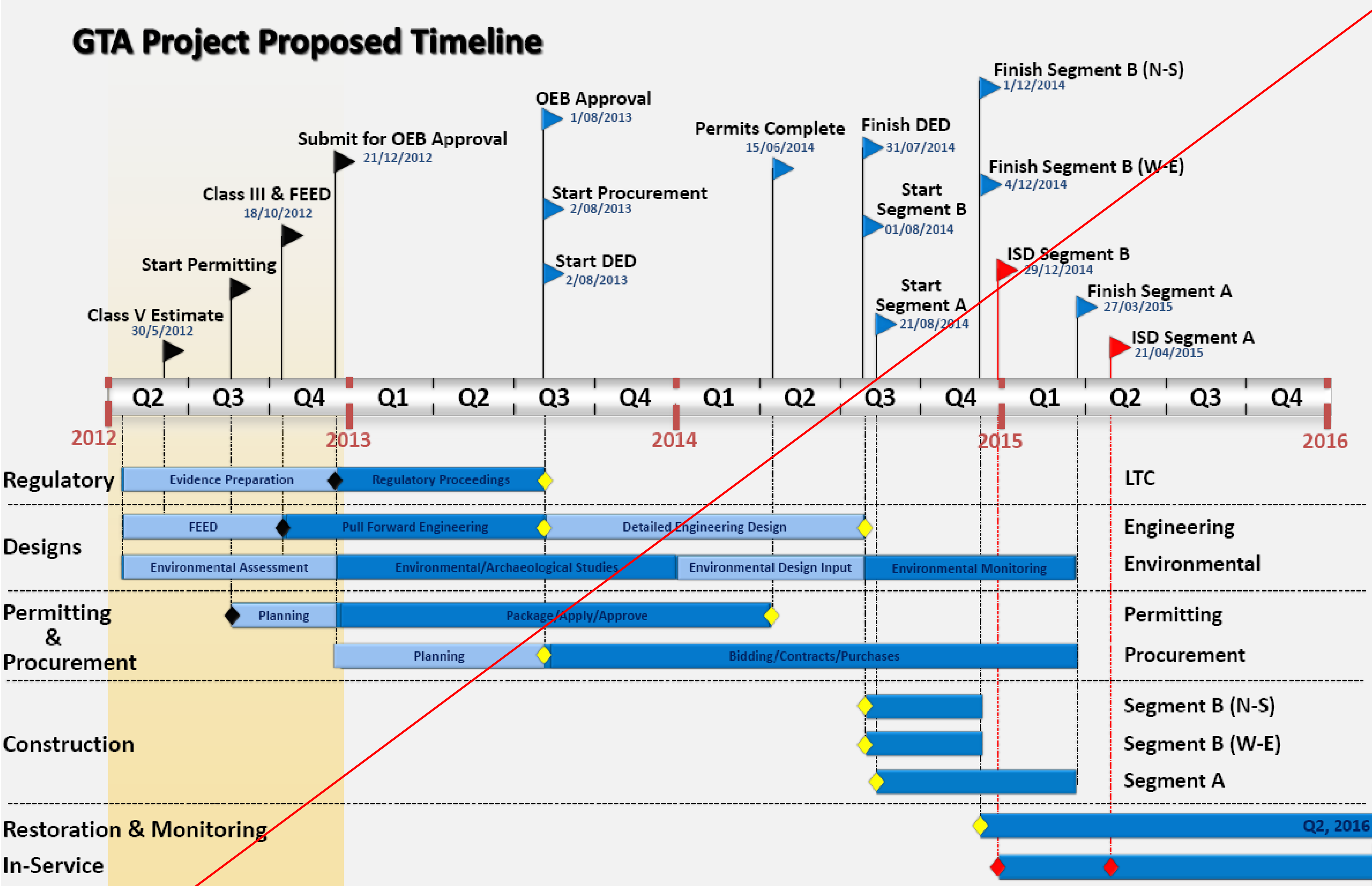
i. An increase in the required PFE expenditure in order to continue work on the critical path items and maintain the ability to meet the in-service date.

ii. A delay in the continuation of the PFE and procurement processes. As stated above, this may directly result in a failure to meet the in-service date of November 1, 2015 due to material lead times on the NPS 42 items.

~~8. The proposed construction schedule is described in Exhibit C, Tab 2, Schedule 2.~~

Filed: 2012-08-12, EB-2012-0451/EB-2012-0433/EB-2013-0074, Exhibit A, Tab 3, Schedule 8, Attachment, Figure 1

GTA Project Proposed Timeline

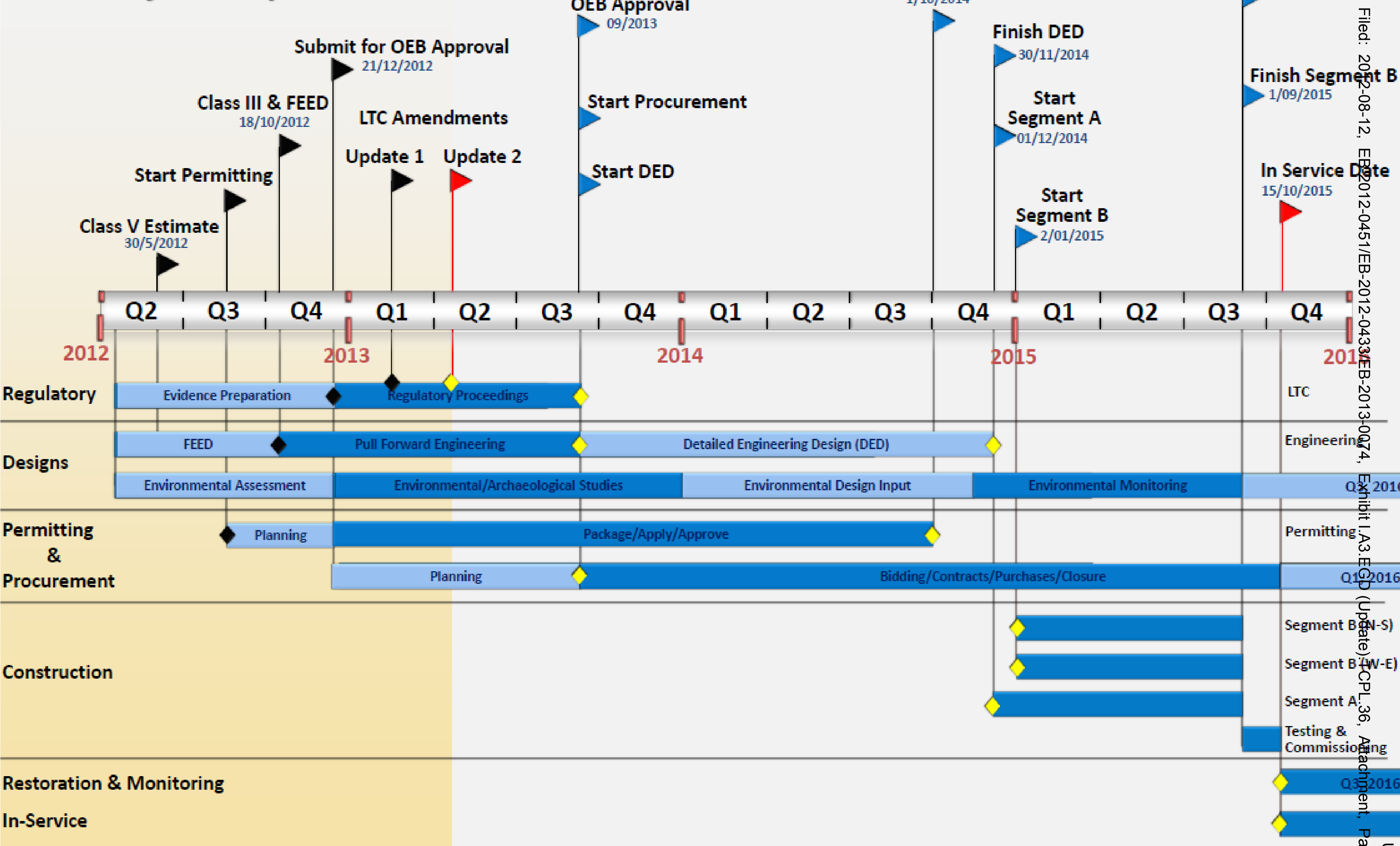


Abbreviations

DED – Detailed Engineering Design	LTC – Leave to Construct	N-S – North South
FEED – Front End Engineering Design	PFE – Pull Forward Engineering	W-E – West East
ISD – In-Service Date		

Figure 1

GTA Project Proposed Timeline



Abbreviations

DED – Detailed Engineering Design
FEED – Front End Engineering Design
LTC – Leave to Construct
OEB – Ontario Energy Board
N-S – North South
W-E – West East

Updated: 2013-04-15
EB-2012-0451
Exhibit A
Tab 3
Schedule 8
Attachment

~~MINIMUM~~ DESIGN SPECIFICATIONS – SEGMENT A – NPS ~~36~~ ~~MAIN~~42 PIPELINE

Description	Line Pipe	Units
External Diameter	~~914~~1067	mm
Wall Thickness	~~17.5~~19.05	mm
Grade	~~448~~483	MPa
Specification	CSA Z245.1	
Material Toughness	CSA Z245.1	
Pipe Coating Specifications	CSA Z245.20	
Cathodic Protection	CGA OCC-1	
Coating	Fusion Bond Epoxy	
Class Location	4	
Design Pressure	6,450	kPa
Hoop Stress at Design Pressure	37.~~6~~4 % SMYS*	
Maximum Operating Pressure (MOP)	6,450	kPa
Hoop Stress at MOP	37.~~6~~4 % SMYS~~*~~*	
Minimum Cover	1.2	m
Fittings	CSA Z245.11	
Flanges	CSA Z245.12	
Valves	CSA Z245.15	
Test Medium	Water	
Strength Test Hydrostatic Pressure	17,~~128~~247 (@ Low Point)	kPa
Hoop Stress at Strength Test Pressure	100% SMYS*	
Leak Test Hydrostatic Pressure	~~9030~~9,030 (@ High Point)	kPa

* SMYS – Specified Minimum Yield Strength

~~MINIMUM~~ DESIGN SPECIFICATIONS – SEGMENT A – NPS 36
~~180~~315 m TIE-IN

Description	Line Pipe	Units
External Diameter	914	mm
Wall Thickness	17.5	mm
Grade	448	MPa
Specification	CSA Z245.1	
Material Toughness	CSA Z245.1	
Pipe Coating Specifications	CSA Z245.20	
Cathodic Protection	CGA OCC-1	
Coating	Fusion Bond Epoxy	
Class Location	4	
Design Pressure	4,482	kPa
Hoop Stress at Design Pressure	26.1 % SMYS*	
Maximum Operating Pressure (MOP)	4,482	kPa
Hoop Stress at MOP	26.1% SMYS*	
Minimum Cover	1.2	m
Fittings	CSA Z245.11	
Flanges	CSA Z245.12	
Valves	CSA Z245.15	
Test Medium	Water	
Strength Test Hydrostatic Pressure	17,128 (@ Low Point)	kPa
Hoop Stress at Strength Test Pressure	100% SMYS*	
Leak Test Hydrostatic Pressure	6,300 (@ High Point)	kPa

* SMYS – Specified Minimum Yield Strength

~~MINIMUM~~ DESIGN SPECIFICATIONS – SEGMENT B – NPS 36 ~~MAIN~~ PIPELINE

Description	Line Pipe	Units
External Diameter	914	mm
Wall Thickness	17.5	mm
Grade	448	MPa
Specification	CSA Z245.1	
Material Toughness	CSA Z245.1	
Pipe Coating Specifications	CSA Z245.20	
Cathodic Protection	CGA OCC-1	
Coating	Fusion Bond Epoxy	
Class Location	4	
Design Pressure	4,482	kPa
Hoop Stress at Design Pressure	26.1% SMYS*	
Maximum Operating Pressure (MOP)	4,482	kPa
Hoop Stress at MOP	26.1% SMYS*	
Minimum Cover	1.2	m
Fittings	CSA Z245.11	
Flanges	CSA Z245.12	
Valves	CSA Z245.15	
Test Medium	Water	
Strength Test Hydrostatic Pressure	17,128 (@ Low Point)	kPa
Hoop Stress at Strength Test Pressure	100% SMYS*	
Leak Test Hydrostatic Pressure	6,300 (@ High Point)	kPa

* SMYS – Specified Minimum Yield Strength

HYDROSTATIC TEST PROCEDURES

1. All hydrostatic testing will be completed in accordance with the Enbridge Construction and Maintenance Manual and the Enbridge Hydrostatic Testing Procedures which meet the requirements of the applicable codes currently adopted by the Technical Standards and Safety Authority ("TSSA"), namely the applicable CSA Z662 Oil and Gas Pipeline Systems and Ontario Regulation 210/01 ("Oil and Gas Pipeline Systems").

2. The Hydrostatic Test Procedures described herein are applicable to the approximate ~~48.9~~ 23 kilometres ("km") of proposed ~~new~~ NPS 36 pipeline and 21 km of proposed NPS 42 pipeline.

Testing Procedures Summary

3. The proposed pipelines will be hydrostatically tested in two parts: a strength test and a leak test.

Strength Test

4. The strength test is a four hour test, conducted at a pressure corresponding to 100% of the Specified Minimum Yield Strength ("SMYS") of the pipe. For all sections of the proposed NPS 36 pipeline, the strength test pressure will be 17,128 kPa (2,484 psi) at the lowest point. For the NPS 42 pipeline, the strength test pressure will be 17,247 kPa (2,501 psi) at the lowest point.

Leak Test

5. The leak test is conducted immediately following the strength test for a duration of four hours. The leak test pressure is 1.4 times greater than the ~~Design~~

~~Pressure.~~design pressure. This corresponds to 9,030 kPa (1,310 psi) at the highest point~~,~~ for the ~~Segment A Main Pipeline~~NPS 42 pipeline and 6,300 kPa (914 psi) at the highest point~~,~~ for the ~~Segment A 180 m Tie-In and Segment B Main Pipeline.~~NPS 36 pipelines.

Test Water

6. As municipal water will be available nearby, test water is proposed to be obtained from the applicable municipality in the location of the hydrostatic test and discharged per their permit approval conditions. Appropriate permits will be obtained and Enbridge Construction and Maintenance Manual procedures will be followed in the disposal of the test water.

TOTAL ESTIMATED PROJECT COST

1. The total estimated project cost for the GTA Project is $~~602.9~~686.5 million, including Interest During Construction ("IDC"). Below is a summary description of the major cost areas of the project. /u

Table 1 – Summary Total Estimated Project Cost /u

Item No.	Description	Cost ($millions) [1,2]
1.0	Base Project Cost (2013 dollars)	~~502.0~~548.7
2.0	Contingency	~~62.2~~84.5
3.0	Escalation	~~27.1~~33.6
4.0	Interest During Construction	~~11.6~~19.8
5.0	Total Estimated Project Cost	~~602.9~~686.5

Table 2 shows the Detailed Total Estimated Project Costs.
This information has been filed in confidence as described in ~~Paragraph~~paragraph 6 below.

Estimated Project Costs

2. The estimated project costs were developed for the project in its entirety. The estimated costs provide a consistent approach to the design, development and

[1] Items 1 to 4 do not exactly sum to Item 5 due to the rounding of costs for the purposes of this summary table.
[2] The Segment A pipeline cost estimate has been updated based on currently available information. Elements of Segment A have not yet had the same level of field survey and engineering work as the remainder of the GTA Project due to time constraints associated with preparing the cost estimate for Update No. 6. As such, there is greater uncertainty and variability on Segment A's portion of the cost estimate.

construction of the pipelines and associated facilities. Using this approach allows project activities to be planned and managed to achieve economies of scale, scope, and execution. Therefore the project cost estimate would not be valid by applying a simple division of project costs between the respective project segments or elements, nor would it be valid if the project schedule and timing were altered.

3. A dedicated multi-disciplinary team is in place to manage the project given its scope. The project has adopted a project management framework as described in Exhibit C, Tab 2, Schedule 3. This framework, and in particular the risk based methods outlined within it, have been utilized for the development of the project costs and to ensure governance, cost, and schedule controls.

4. The project cost estimate was developed according to the Association for the Advancement of Cost Engineering International ("AACE") guidelines, which are the industry standard in cost estimate development. ~~The project cost estimate is a bottom-up cost estimate which meets the criteria for a Class 3 estimate under AACE guidelines.~~ The construction cost estimate ~~is a bottom-up estimate and~~ is based on a contractor style crew by crew make up complete with all the tools and equipment required to perform the work. The materials estimate is based on budgetary quotes for all major equipment from various approved vendors. ~~Indirect costs have been calculated and are not based on factored estimates.~~ Key deliverables developed in order to determine the cost estimate include a detailed project execution plan, construction execution plans, schedule and a design basis memorandum.

5. Rigorous risk assessment sessions were held inclusive of constructability, process hazard analysis, system operability, and design basis reviews. Information from these sessions was then used to assess risk and subsequently contingency. Contingency was determined through the use of a proprietary parametric model based on Rand Corporation and Independent Project Analysis ("IPA") studies of

industrial projects over the past 40 years coupled with actual projects throughout the Enbridge group of companies. Using this information, the process is customized and calibrated, and takes into account systemic and project specific risks that would impact the capital cost or schedule. The estimate of potential market escalation has been calculated using a set of predictive escalation indices that were developed by an external consultant (Global Insight) who specializes in macro-economic forecasting.

6. Assuming the Ontario Energy Board (the "Board") grants leave to construct, further cost definition will continue during the procurement processes. The various costs are therefore summarized at a high level in order to avoid compromising any procurement processes required. A detailed summary will be filed with the Board confidentially.

7. The Company is taking steps to mitigate risks with construction delays to meet the required in-service dates and to also mitigate project costs and overruns. These steps include the advancement of work that would otherwise be performed in the detailed engineering and design phase. It also includes the continuation of environmental work, permit applications, and procurement planning. This is described in more detail in Exhibit A, Tab 3, ~~Schedule~~Schedules 8 and 9. /u

Table 2 – Detailed Total Estimated Project Costs /u

	WORK BREAKDOWN STRUCTURE	
Summary Roll-up	**Description**	**Cost**
Project Engineering, Development, Execution and Administrative /General		
	Project Development	
	Project Execution	
	Administrative and General	
	Insurance	
	Engineering	
Total Project Engineering, Development, Execution and Administrative /General		
Mainline		
Parkway West to Albion ~~(includes 180 m tie-in to NPS 36 Parkway North)~~		
	Land and Easements	
	Pipe and Coating	
	Valves	
	Induction Bends	
	Fittings, Flanges, and Other	
	Construction, Testing, Surveys, and Construction Management	
	Commissioning and Start-Up	
Keele/CNR to Don Valley Junction		
	Land and Easements	
	Pipe and Coating	
	Valves	
	Induction Bends	
	Fittings, Flanges, and Other	
	Construction, Testing, Surveys, and Construction Management	
	Commissioning and Start-Up	
Don Valley Junction to Sheppard Ave		
	Land and Easements	
	Pipe and Coating	
	Valves	

Induction Bends
Fittings, Flanges, and Other
Construction, Testing, Surveys, and Construction Management
Commissioning and Start-Up

Total Mainline

Facilities

Parkway West ~~Gate Station (Meter Run)~~Initiation Point

Land and Easements
Meter Runs
Regulation Runs
Heating
Odourization
Other Costs
Construction and Construction Management
Commissioning and Start Up

Parkway West Gate Station and Parkway Bypass Regulation

Land and Easements
Meter Runs
Regulation Runs
Heating
Odourization
Other Costs
Construction and Construction Management
Commissioning and Start Up

Albion Road Gate Station

Land and Easements
Meter Runs
Regulation Runs
Heating
Odourization
Other Costs
Construction and Construction Management
Commissioning and Start Up

Keele/CNR Feeder Station (Modifications)

Land and Easements
Meter Runs

Regulation Runs
Heating
Odourization
Other Costs
Construction and Construction Management
Commissioning and Start Up

Buttonville/Highway 407 Meter and Regulation Station

Land and Easements
Meter Runs
Regulation Runs
Heating
Odourization
Other Costs
Construction and Construction Management
Commissioning and Start Up

Jonesville/Eglinton Meter and Regulation Station

Land and Easements
Meter Runs
Regulation Runs
Heating
Odourization
Other Costs
Construction and Construction Management
Commissioning and Start Up

Total Facilities

Base Project Cost

Contingency

Base Project Cost and Contingency

Escalation

Interest During Construction

Grand Total

PROPOSED CONSTRUCTION SCHEDULE

1. The proposed project schedule is outlined in Exhibit A, Tab 3, Schedule 8. The proposed construction schedule is as follows:

Segment A

- Commence Construction ~~August~~December 2014
- Completion of Construction ~~March~~September 2015
- In-Service ~~April~~October 2015
- Completion of Reinstatement ~~September 2015~~April 2016
- Final Inspection ~~March~~September 2016

Segment B

- Commence Construction ~~August 2014~~January 2015
- Completion of Construction ~~December 2014~~September 2015
- In-Service ~~December 2014~~October 2015
- Completion of Reinstatement ~~September 2015~~April 2016
- Final Inspection ~~March~~September 2016

2. The construction of the entire project will take approximately ~~eight~~nine months. ~~Both~~ Segment A ~~and Segment B are~~is scheduled to start construction in ~~August~~December 2014 and Segment B is scheduled to start construction in January 2015. Construction on both ~~Segments~~segments will proceed in parallel until completion of the respective segments. The construction schedule is driven by ~~mainline construction activities which will be performed by a mainline contractor. Construction activities also include~~ an extensive Horizontal Directional Drilling

("HDD") program which will be performed by ~~a separate~~an HDD contractor working in parallel to the mainline contractor.~~ HDD construction activities require support from the mainline contractor and as such, the HDD construction schedule has been optimized to meet the mainline construction schedule. Extending the construction schedule of the HDD program beyond that of the mainline contractor's would have a negative impact on project costs in order of approximately $70 million due to the need to keep additional mainline construction crews on-site for support.~~

3. Enbridge will construct the pipeline using qualified construction contractors following approved construction specifications. Site specific conditions found on this project will be appropriately addressed.

4. Restoration monitoring will be conducted through to 2016 for both Segment A and B to ensure successful environmental mitigation.

5. A post construction report will be issued upon completion of the project as required by the Ontario Energy Board.

PROJECT BENEFITS AND ECONOMICS

1. The ~~GTA Project offers~~purpose of this evidence is to describe the project benefits and economic feasibility associated with the ~~following:~~GTA Project.

- ~~The increased operational flexibility and lower operational risk associated with the distribution system. The benefits to system operations are described in Exhibit A, Tab 3, Schedule 6, Paragraph 8;~~
- ~~The increased diversity of entry points and the lower operational risk and greater flexibility provided with this diversity. The benefits to system operations are described in Exhibit A, Tab 3, Schedule 6, Paragraph 8;~~
- ~~Increased upstream reliability and diversity. The benefits are described in Exhibit A, Tab 3, Schedule 5, Page 18;~~
- ~~Capacity to serve customer growth and associated revenue; and,~~
- ~~Efficiency in upstream transportation and associated savings.~~

~~2. Benefits associated with reliability, diversity, and flexibility are substantial and in fact, are the primary purpose of this reinforcement project. These benefits are critical to the continuing operation of gas distribution in the GTA, but are difficult to quantify or monetize. Therefore these benefits are not included in the economic analysis shown below. The only benefit streams that have been included in the economic analysis are the associated revenue from customer growth and the upstream transport benefits. Details and assumptions of customer growth benefits can be found in paragraph 7. Details and assumptions of benefits from upstream transportation can be found in paragraph 9. Other potential benefits are discussed in paragraph 14, but they are not included in the economic feasibility analysis. The economics, are positive, and are shown in order to provide a complete examination of the project.~~

~~METHODOLOGY~~

~~The overall feasibility of the project has been determined using the methodology that adheres to the~~ /u

2. The assets to be used for transportation purposes will be referred to as the "Albion Pipeline" for the purpose of the economics and rate methodology (Exhibit E only) in order to distinguish them from the assets that will be used for the purpose of providing distribution service. The Albion Pipeline includes the pipeline and facilities that will connect Parkway West Gate Station to Albion Road Gate Station. The Albion Pipeline has a distribution component and a transportation component, as explained below.

3. The distribution assets include all of Segment B and Segment A's Parkway West Gate Station, 315 metre ("m") tie-in, Parkway Bypass Station, Albion Road Gate Station, and 40% of the Albion Pipeline capacity. The transportation asset includes 60% of the Albion Pipeline capacity. The capacity allocation and the associated method of cost recovery for the Albion Pipeline are described at Exhibit E, Tab 1, Schedule 2. /u

Methodology and Results

4. The economic feasibility for the distribution and transportation assets were assessed under the following guidelines as recommended by the Ontario Energy Board (the "Board"):

~~3.~~
- For the distribution assets, "*Ontario Energy Board Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario*" and as laid out in the ~~Ontario Energy~~ Board's ~~(the "Board")~~ EBO 188 "Report to the Board" dated January 30, 1998.
- For the transportation asset, *"Filing Guidelines on Economic Tests for Transmission Pipeline Applications*" as set out in the Board's EBO 134 "Report to the Board" dated June 1, 1987, plus the additional filing

requirement described in the Board Letter dated February 21, 2013 (Board File No. EB-2012-0092).

5. Both Segment A and Segment B are required for ratepayers to realize the associated benefits. Correspondingly, the overall economics combine the costs and quantifiable benefits of both segments. As a result, a Discounted Cash Flow ("DCF") was prepared on the basis of the entire project over a 40-year horizon which is in accordance with both EBO 188 and EBO 134.

~~4.~~6. The economic feasibility evidence ~~for the GTA Project system reinforcement~~ has been prepared using the Company's feasibility parameters pursuant to the Board's Decision ~~with Reasons~~ in the Company's ________EB-~~2012-0054~~2013-0045 Rate ~~Application. The economic feasibility of this project has been calculated by discounting the project's incremental cash flows forecast over a 40-year project horizon~~Order. A summary of the input parameters can be found on pages 8 and 9.

Cash Outflows: Capital, O&M, and Other Costs

~~5.~~ The upfront capital cost for the proposed facilities is estimated to be $~~575.3~~652.1 million~~, exclusive of escalation,~~ and includes the costs for mains, stations, land, land rights, contingencies, and overheads~~.~~ /u

~~6.~~7. , in 2013 dollars. The detailed breakdown of the total estimated project cost is provided in Exhibit C, Tab 2, Schedule 1.

8. The annual average Operation and Maintenance ("O&M") cost is estimated to be $13.3 million. The O&M includes leak survey, damage prevention, cathodic protection, direct maintenance, corporate RCAM allocation and incremental O&M for customer attachment. /u

9. On-going capital for investigative digs arising from in-line inspection was also included in the economic feasibility analysis ~~for the GTA Project includes estimated capital~~ . The capital anticipated for this activity is approximately $1.0 million and occurs every seven years starting in 2021.

In-line inspection also has an O&M component which will occur on the same time interval

10. Other costs include:

- ~~7.~~ Estimated capital costs[1] of $~~346.4~~379.5 million for the services[2] associated with attaching ten years of incremental customer additions as outlined in Exhibit A, Tab 3, Schedule 4~~. The Company is not seeking approval for the services costs with this application but has incorporated them into the analysis as these customers are supported by the proposed GTA Project. The customer growth does not include customers outside the GTA Project Influence Area.~~;

- ~~8. The economic feasibility analysis of the project also includes a series of future~~Future reinforcement projects[3] anticipated in the years 2017, 2018, 2019, and 2020 at estimated costs of $21.0 million, $16.4 million, $13.0 million and
$0.3 million, respectively~~. The capital amounts for these future reinforcement projects have been included in the feasibility analysis for completeness. The Company is not seeking approval for these future reinforcement projects in this application.~~;

- ~~The economic feasibility includes~~Gas costs associated with attaching the ten years of incremental customer additions; and
- Income and municipal taxes.

Cash Inflows and Savings

[1] The Company is not seeking approval for the services costs with this application but has incorporated them into the analysis since these customers will be supported by the proposed GTA Project. The customer growth does not include customers outside the GTA Project Influence Area.
[2] Services include the costs for distribution mains, services and meters based on the ~~2012~~2013 capital budget.
[3] The Company is not seeking approval for these future reinforcement projects in this application. The capital amounts for these future reinforcement projects have been included in the feasibility analysis for completeness.

11. The economic feasibility includes the revenue generated from the ten years of incremental customer additions, the expected gas transportation savings, and the transportation services charges from the contracted shippers on the Albion Pipeline, which includes: /u

~~9.~~ • The net transportation savings as outlined at Exhibit A, Tab 3, Schedule ~~3.~~ ~~The~~9. The net transportation savings considers impacts from Union Gas' Parkway West (EB-2012-0433) and Brantford-Kirkwall Parkway D (EB-2013-0074) projects, in addition to TransCanada's final Mainline tolls pursuant to the National Energy Board's ("NEB") Toll Order TG-006-2013[4]. These forecasted transportation savings have only been included until 2025. ~~For feasibility purposes, the amounts beyond 2025 have been assumed to be zero. It is expected savings will continue in the periods beyond 2025.~~[5] /u

• The revenue associated with providing transportation services to shippers on the Albion Pipeline from Parkway West to Albion. The revenue and transportation service charge are further described in Exhibit E, Tab 1, Schedule 2. /u

Results

The DCF results[6]

~~SUMMARY~~ /u

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[4] The NEB's Toll Order TG-006-2013 (issued June 11, 2013) made TransCanada's Compliance Filing tolls final and effective July 1, 2013.

[5] For feasibility purposes, the amounts beyond 2025 have been assumed to be zero for conservatism, however, it is expected savings will continue in the periods beyond 2025.

[6] DCF analysis is a requirement of EBO 188 and a requirement of Stage 1 analysis for EBO 134. Stage 2 and Stage 3 feasibility tests, as suggested by EBO 134, were not required given the DCF feasibility test yielded a PI > 1.0. However, other benefits and public interest factors were considered in the project development and are described in this exhibit.

~~10. The results~~ of the feasibility analysis indicate a Profitability Index ("PI") of 1.~~02~~73 and a Net Present Value ("NPV") of $~~20.3~~667.4 million, in ~~2012~~2013 constant dollars.

~~11.~~12. A summary of the ~~inputs and~~feasibility results ~~of the feasibility is provided on pages 6 and 7, while~~ can be found on page 9. The complete DCF results can be found in Attachment 1 ~~shows detailed feasibility parameters and results.~~ .

~~END NOTES~~

~~12. The NPV and PI shown are based on a constant dollar 2012 estimate of the project and other costs and revenues. This is consistent with other Leave to Construct applications. The total estimated project cost shown in Exhibit C, Tab 2, Schedule 1 includes cost escalations for future years and is therefore the amount estimated to be spent in nominal dollars, and is the amount sought for approval.~~

13. The present value of the project's total net operating cash flows before taxes is $~~1,110.9~~2,026.6 million. ~~Distribution related cash flows account for approximately 68% of~~Of this total amount ~~with the remaining 32% driven by~~, the forecasted transportation savings account for approximately 57.3%, distribution related cash flows comprise 32.3% with the remaining 10.4% attributable to the transportation services charge. /u

~~15.~~14. An un-redacted version of the Project Benefits and Economics has been filed in confidence. Some of the project cost data utilized in the economic analysis is commercially sensitive as described in Estimated Project Costs, Exhibit C, Tab 2, Schedule 1, paragraph 6.

~~No externalized~~

15. Sensitivity analysis can be found at Exhibit A, Tab 3, Schedule 9. The sensitivity analysis scenarios include variations on the current base case: 50% and 75% /u

expected gas transportation savings, 0% transportation services charges (i.e. no contracted shippers on the Albion Pipeline), no distribution customer additions, and a 10% increase in all capital costs (including upfront GTA Project capital, and future reinforcement projects, mains, and services).

Project Benefits and Public Interest Factors

16. Benefits associated with reliability, diversity, and flexibility are substantial and are the primary purpose of this project. These benefits ~~were~~ are critical to the continuing operation of gas distribution in the GTA but are difficult to quantify or monetize, such as:

- Increased operational flexibility and lower operational risk associated with the distribution system, as described in Exhibit A, Tab 3, Schedule 6;
- Increased diversity of entry points and the lower operational risk and greater flexibility provided with this diversity, as described in Exhibit A, Tab 3, Schedule 6;
- Increased upstream reliability and diversity, as described in Exhibit A, Tab 3, Schedule 5;
- Capacity to serve customer growth; and
- Efficiency in upstream transportation.

Therefore these benefits are not included in the economic analysis~~, such as~~. The project benefits that have been included in the economic feasibility are the associated revenue from customer growth and the expected upstream transport benefits.

17. The Board recently instituted a new filing requirement (Guideline 14, Board File No. EB-2012-0092) under EBO 134:

> *"Any project brought before the Board for approval should be supported by an assessment of the potential impacts of the proposed natural gas pipelines on the existing transportation pipeline infrastructure in Ontario, including an assessment of the impacts on Ontario consumers in terms of cost, rates, reliability, and access to supplies."*

Further to the considerations described in Exhibit A, Tab 3, Schedule 1, pages 10 to 14:

- The Albion Pipeline potentially eliminates the need for duplicative pipelines and/or facilities resulting in less environmental and community impacts. As a result, Enbridge's distribution customers and shippers will realize savings through the combined distribution and transportation facilities. /u
- Reliability: As outlined in Exhibit A, Tab 3, Schedule 6, there are significant reliability benefits associated with the proposed facilities, including the ability to procure more reliable upstream transport, diversification of key entry points into the GTA system, and diversification of critical supply lines with the downstream backbone of the GTA system. The ability to lower pressures on key supply lines also increases overall system reliability.
- Access to supplies: The project will allow access to additional supplies through Parkway from Niagara and/or Dawn to replace a potential reduction of TransCanada's Mainline capacity as outlined in Exhibit A, Tab 3, Schedule 5. As a result of the capacity available for shippers, the project will also increase market access to supplies for other consumers both in Ontario and beyond. /u

~~14.~~18. Further public interest factors include the consumer economic advantage of ~~utilization of~~ natural gas as compared to other fuels. ~~However, for~~ For reference, natural gas is currently the most economical choice for home and water heating in Ontario. Compared to electricity, heating oil and propane, natural gas is about 70% less expensive than the next most economic alternative. The GTA Project is annually expected to permit an average of approximately 14,000 new residential customer additions over a ten year period. For the typical residential household, the savings from using natural gas compared to electricity, heating oil~~,~~ or propane is approximately $2,000 per year. In total, the average annual savings for all residential customer additions included in the forecast is ~~roughly~~approximately $28 million. Apartment, commercial and industrial customer annualized savings over alternate fuels would substantially increase the annualized savings that ~~accrues~~accrue to energy consumers.

~~15.~~19. ~~A non-redacted version of the Project Benefits and Economics has been filed in confidence. Some of the project cost data utilized in the economic analysis is commercially sensitive as described in Estimated Project Costs, Exhibit C, Tab 2, Schedule 1, paragraph 6.~~

SUMMARY

SUMMARY OF INPUTS

Incremental Customer Additions

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Residential	13,112	13,471	13,955	14,062	14,245	14,448	14,662	14,662	14,662	14,662
Commercial	1,370	1,412	1,328	1,331	1,328	1,339	1,347	1,347	1,347	1,347
Apartment	75	75	73	72	72	71	71	71	71	71
Industrial	3	3	2	2	2	2	2	2	2	2
Total	**14,560**	**14,961**	**15,358**	**15,467**	**15,647**	**15,860**	**16,082**	**16,082**	**16,082**	**16,082**

Average Annual Volume per Customer

$(10^3 m^3)$	
Residential	2.510
Commercial	19.921
Apartment	160.301
Industrial	114.225

Total Cumulative Volumes*

$(10^3 m^3)$	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Residential	16,456	49,817	84,237	119,398	154,923	190,933	227,466	264,268	301,069	337,871	356,272
Commercial	13,646	41,356	68,648	95,133	121,618	148,182	174,936	201,770	228,603	255,437	268,854
Apartment	6,011	18,034	29,896	41,518	53,060	64,521	75,903	87,284	98,665	110,047	115,737
Industrial	171	514	800	1,028	1,256	1,485	1,713	1,942	2,170	2,399	2,513
Total	**36,284**	**109,721**	**183,580**	**257,077**	**330,857**	**405,122**	**480,018**	**555,263**	**630,508**	**705,753**	**743,376**

Note* 50% effectivity considered for the first year of customer additions

Savings on Gas Transportation

($s)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
System Gas	9,322,066	40,855,698	42,796,175	38,440,253	39,860,283	39,648,400	39,325,042	39,376,272	39,321,005	40,898,009	40,414,020
Direct Purchase	1,640,827	10,112,877	10,020,527	9,944,412	9,937,537	9,933,580	9,888,104	9,867,995	9,848,512	9,869,890	9,829,984
	10,962,892	**50,968,576**	**52,816,702**	**48,384,664**	**49,797,821**	**49,581,980**	**49,213,146**	**49,244,267**	**49,169,517**	**50,767,899**	**50,244,004**

OF INPUTS

Incremental Customer Additions

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Residential	12,277	12,607	13,034	13,148	13,331	13,535	13,748	13,748	13,748	13,748
Commercial	1,291	1,327	1,250	1,253	1,250	1,261	1,269	1,269	1,269	1,269
Apartment	71	71	69	69	68	67	67	67	67	67
Industrial	3	3	2	2	2	2	2	2	2	2
Total	**13,642**	**14,008**	**14,355**	**14,472**	**14,651**	**14,865**	**15,086**	**15,086**	**15,086**	**15,086**

Average Annual Volume per Customer

($10^3 m^3$)	
Residential	2.568
Commercial	20.230
Apartment	154.877
Industrial	109.481

Total Cumulative Volumes*

($10^3 m^3$)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Residential	15,764	47,715	80,638	114,255	148,254	182,750	217,782	253,087	288,392	323,696	341,349
Commercial	13,058	39,540	65,606	90,924	116,242	141,640	167,231	192,903	218,575	244,247	257,083
Apartment	5,498	16,494	27,336	38,022	48,631	59,086	69,462	79,839	90,216	100,593	105,781
Industrial	164	493	766	985	1,204	1,423	1,642	1,861	2,080	2,299	2,409
Total	**34,484**	**104,241**	**174,346**	**244,187**	**314,332**	**384,900**	**456,118**	**527,690**	**599,263**	**670,835**	**706,621**

Note* 50% effectivity considered for the first year of customer additions

Savings on Gas Transportation

($s)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Savings	**25,930,140**	**158,790,547**	**164,329,966**	**202,203,801**	**171,309,917**	**166,788,225**	**166,648,873**	**167,019,723**	**167,275,870**	**171,338,847**	**171,014,830**

SUMMARY OF INPUTS (cont'd)

Capital Investment

Mains	[redacted]
Stations	
Land/Land Rights	
Total	$~~575,309,332~~652,144,124
Future Reinforcement Projects	
2017	$21,000,000
2018	$16,400,000
2019	$13,000,000
2020	$250,000
Capital Maintenance Costs	$5,230,240
Services[7]	$~~346,393,523~~379,533,696
Total Capital	~~$972,352,854~~$1,087,558,060
Total ~~Transport~~Transportation Savings	~~511,151,468~~$1,732,650,739
Total Transportation Services Charge	$471,256,624

SUMMARY OF RESULTS

Net Present Value (40 years)	$~~20,290,078~~667,432,377
Profitability Index (40 years)	1.~~02~~73

[7] Services include the costs for distribution mains, services and meters based on the ~~2012~~2013 capital budget.