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June 18, 2013

VIA COURIER, EMAIL and RESS

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

**Re: Enbridge Gas Distribution Inc. ("Enbridge")
EB-2012-0451 - Greater Toronto Area ("GTA") LTC Project
Interrogatory Responses**

Further to the Ontario Energy Board's Procedural Order No. 2 dated May 8, 2013, enclosed please find the Undertaking Responses of Enbridge for the above noted proceeding.

This submission was filed through the Board's Regulatory Electronic Submission System and will be available on the Company's website at www.enbridgegas.com/gtaproject.

Please contact me if you have any questions.

Yours truly,

[Original Signed]

Shari Lynn Spratt
Supervisor Regulatory Proceedings

cc: EB-2012-0451, EB-2012-0433, and EB-2013-0074 Interested Parties

UNDERTAKING JT1.1

UNDERTAKING

TR 1, page 14

To confirm whether TransCanada is obligated under the MOU to build from Albion to Maple in order to retain capacity to Enbridge pipeline.

RESPONSE

The undertaking appears to contain a grammatical error and we assume it to be, “to confirm whether TransCanada is obligated under the MOU to build from Albion to Maple in order to retain capacity on the Enbridge Pipeline.”

In Schedule “D” of the MOU, under “Impact of Elections”, certain provisions of the applicable election (in this case, election #2) are to be incorporated into the terms of the TBO Agreement, also known as the Transportation Service Agreement (“TSA”); included is section 7 of Schedule “B” which states that “TransCanada will construct, own, operate and maintain the TransCanada Maple Pipeline.” Further, the TSA will contain the provision, as set out in Section 4(l) of Amending Agreement #2:

> TransCanada agrees to work with the Eastern local distribution companies and the market in a cooperative and timely manner, to establish terms and conditions, to be brought to the NEB for approval, under which TransCanada could expand the TransCanada System for short haul service requests on a commercially reasonable basis.

The MOU also requires TransCanada (and Enbridge) to diligently and expeditiously pursue to the regulatory approvals necessary to enable the parties to meet their obligations under the MOU.

TransCanada and Enbridge have not yet concluded negotiating the definitive terms of the TSA. Currently, Enbridge has proposed a term which states that TransCanada shall utilize the gas transportation services provided hereunder only to provide gas transportation services pursuant to the TransCanada Tariff or for its own operational purposes. Also, TransCanada would be paying for service under the TSA whether or not TransCanada was using the service. These terms combined with the obligations in the MOU stated above have the effect of obligating TransCanada to build the Albion to Maple pipeline in connection with its use of the GTA pipeline.

Witness: M. Giridhar

UNDERTAKING JT1.2

UNDERTAKING

TR 1, page 15

To provide the section of STAR which provides exemption.

RESPONSE

Pursuant to section 1.7.1 of STAR, the OEB may grant an exemption from any provision of the Rule in whole or in part, and such exemption may be subject to conditions or restrictions. Enbridge would like to take this opportunity to explain the principles underpinning the MOU with TransCanada and the manner in which the public interest considerations underpinning STAR and related OEB decisions are incorporated within the MOU.

The Intent of the Discussions amongst Enbridge, Union and TransCanada

In its EB-2011-0210 Decision, the OEB admonished Union, Enbridge and TransCanada to consult to determine the most efficient development and use of proposed infrastructure to the benefit of Ontario ratepayers (see pages 126-127). To this end, Enbridge has consulted with and negotiated arrangements with both TransCanada and Union in a non-discriminatory and transparent manner, in order to effect a co-ordinated build of much needed gas infrastructure that provides continued safe and reliable distribution service in the GTA and market access for customers in Eastern Canada. The discussions with TransCanada arose in relation to an open season conducted by TransCanada in 2012 and responded to TransCanada's desire to provide services requested in the open season. The principles underpinning the TransCanada MOU are listed under Section 2.1 of the response to CME Interrogatory #6 filed at Exhibit I.A1.EGD.CME 6, Attachment 3, page 27. STAR has a similar purpose, to ensure open and non-discriminatory access to transportation services.

The Quid Pro Quo Sharing Arrangement

The TransCanada MOU and its amendments incorporate a quid pro quo principle to give effect to the twin objectives of continued safe and reliable distribution service to the GTA and market access to economical short haul supply. In return for exclusive access to the Enbridge pipeline from Bram West to Albion ("Enbridge Pipeline"), TransCanada must make reasonable commercial efforts under the Transportation Access Procedures ("TAPS") approved by the NEB to provide service through this path if requested by

Enbridge (Section 16, Exhibit I.A1.EGD.CME 6, Page 23). Further, TransCanada must work with the Eastern LDCs (Enbridge, Union, Gaz Metro) and the market in a cooperative and timely manner to expand the TransCanada system for short haul service requests on a commercially reasonable basis, the terms of which shall be brought to the NEB for approval (Section (l), Exhibit I.A1.EGD.CME.6, Attachment 5, page 7).

The Mechanics of the Arrangement

While Enbridge and TransCanada contemplated joint ownership of the Enbridge Pipeline, the parties eventually agreed to a gas transportation service to be provided by Enbridge as the sole owner and operator of the Enbridge Pipeline. Enbridge and TransCanada agreed that the Transportation Service Agreement (“TSA”) would mimic joint ownership of a pipeline rather than a traditional transmission service as the STAR contemplates. Enbridge would use its capacity on the Enbridge Pipeline to provide gas distribution services, and TransCanada would use its capacity to provide transmission service under its Mainline Tariff. Enbridge would not control the gas flows or balancing on the pipeline as it would do for a typical transmission service, except for safety reasons. Neither would Enbridge take custody of the gas from TransCanada. The rate charged to TransCanada would also mimic a joint ownership arrangement.

Accordingly, Enbridge is of the view that provided the principles underpinning the sharing arrangement are upheld by Enbridge and TransCanada, the intent of STAR would be met by TransCanada providing fair and non-discriminatory access to short haul capacity that is desired by the marketplace under the TAPS.

Changes since the TransCanada MOU was Executed

Since the MOU was executed, two events have created uncertainty. First, the NEB Decision on TransCanada’s restructuring proposal has fixed TransCanada’s tolls for a five year term as opposed to the requested two year term, which has impacted TransCanada’s willingness to provide access to short haul services absent the ability to recover the cost of facilitating access. As a result of the NEB Decision, TransCanada has declined to serve Union and Gaz Metro; instead, TransCanada has stated it will use its capacity on the Enbridge Pipeline to meet existing system requirements resulting from a reduction in back haul service on the Great Lakes system and increase in forward haul service through the Dawn to Parkway system.

Secondly, as a result of the Energy East Project, TransCanada has deemed a significant amount of capacity that is currently required to meet the firm distribution loads of the Eastern LDCs as non-renewable past 2015. TransCanada has stated its intent of ensuring that existing firm contracts will be honored, albeit with changes to tariff terms and conditions, prior to the proposed transfer of Mainline capacity to oil service.

Witness: M. Giridhar

This stated intent does not provide comfort to the Eastern LDCs about the price and other terms and conditions under which prospectively unserved firm residential, commercial, and industrial demand will receive service. Accordingly, market access to Mainline capacity under reasonable commercial terms, whether long haul or short haul, is now a concern for all Ontario customers post October 2015.

Enbridge has identified that up to 170,000 TJ/d of capacity required to serve its Ottawa market, or up to 25% of its peak day demand, will be unsecured past October 2015 as a result of the non-renewable status of these arrangements, causing significant reliability concerns for Enbridge's ability to meet winter demand in the Ottawa market post October 2015. Accordingly, Enbridge has requested that TransCanada provide short haul service commencing in November 2015, in accordance with Section 16 of the MOU; that is, TransCanada must use reasonable commercial efforts under the TAPS to accommodate Enbridge's request either through existing or new facilities, subject to exercise of TransCanada's discretion on a non-discriminatory basis and regulatory approval. TransCanada must issue this open season prior to June 30th, 2013. The TAPS does not permit TransCanada to discriminate between holders of existing and new capacity in terms of price. If TransCanada fails to meet its obligations under the MOU, Enbridge may have the option to terminate the MOU.

Moving Forward

Enbridge is of the view that the MOU between Enbridge and TransCanada can address the needs of the Eastern LDCs for economic access to natural gas if all parties act reasonably to develop a solution. As noted in response to Board Staff Interrogatory #48 at Exhibit I.D5.EGD.STAFF.48, negotiations between the Eastern LDCs and TransCanada with respect to the terms and conditions under which TransCanada is able to expand short haul services are continuing and Enbridge hopes to be able to provide a further update prior to the Settlement Conference, in conjunction with an update on the adequacy of the NPS 36 pipe for its Bram West to Albion pipeline. In the event that the negotiations have resulted in an agreement to expand short haul services in a commercially reasonable manner, the OEB could approve the sharing arrangement conditional on NEB approval for the contemplated services.

In the event that negotiations between the Eastern LDC's and TransCanada have not resulted in an agreement to expand short haul services, and TransCanada is unable to demonstrate that it has upheld the quid pro quo principle embodied in the MOU, the OEB may conclude that TransCanada's exclusive access to capacity on the Enbridge Pipeline is not warranted. In this case, if there is no sharing of the GTA pipeline with TransCanada and capacity on the Enbridge Pipeline is not used to meet TransCanada's existing system requirements, Enbridge is of the view that the NPS 36 pipe size will provide significant incremental market access, in conjunction with any additional facilities that may be built from Albion to Maple and the requisite approvals from the

NEB for access to TransCanada's system. If this were to occur, Enbridge could use the incremental 800 TJ/d to meet the needs of its customers outside of the GTA Project Influence Area and reduce or assign a portion of its current short haul capacity of approximately 700 TJ/d on TransCanada's system from Parkway to Maple, thereby releasing existing capacity for the benefit of other customers in Eastern Canada.

Enbridge believes that the best course of action in the circumstances is for consultations between TransCanada and the Eastern LDCs to continue and for the parties to report back prior to the Settlement Conference. It is Enbridge's view that the issue of adequate market access under reasonable commercial terms can only be resolved at the NEB and the tension between the LDC market's desire for economical access to natural gas supplies and TransCanada's desire to optimize the use of its Mainline system is best resolved by consultation rather than conflict resolution. Enbridge, Union, Gaz Metro, and TransCanada are therefore incented to negotiate the optimal use of the GTA Project in good faith.

To summarize, Enbridge would define the issue before the Board regarding STAR and the TransCanada MOU simply as whether the proposed sharing arrangement with TransCanada provides non-discriminatory access to transmission capacity. Enbridge is of the view that the Board will have enough information by the end of July to make that determination. Any proposals for further solicitation of market interest under STAR would not result in a comprehensive solution (for example, the cost to transport gas away from Maple would still be at issue) and would likely cause consideration of the GTA project to be delayed. The proposed November 2015 in-service date for the GTA project is critical both for the distribution needs of the GTA and for market access for the Eastern LDCs. The current NPS 36 design of the Enbridge Pipeline which creates 1600 TJ/d of incremental market access for Eastern markets, in combination with TransCanada's remaining long haul facilities post-conversion, provide adequate market access and such delay is not warranted in the circumstances.

Witness: M. Giridhar

UNDERTAKING JT1.3

UNDERTAKING

TR 1, page 29

To provide a response to GEC 5(d), to indicate how much load would need to decrease to attain minimum pressure without Segment B or the north-south portion of Segment B; and GEC 5(e): to respond to the question under a scenario in which the Don Valley line operating pressure is not reduced from 450psi to 375psi, specifically, if Segment A and the East-West portion of Segment B are constructed but the North-South portion of Segment B is not constructed, will the peak day pressure at station b fall below the minimum number under 2015-16 design conditions

RESPONSE

In 2015, without operating pressure reductions and with Segment A only, there is a supply shortfall of 11 TJ/day at Station B. Minimum inlet pressures at Station B are not maintained.

In 2015, with original operating pressures and Segment A as well as the east-west portion of Segment B and the associated facility at Buttonville, there is additional capacity of 64 TJ/day at Station B. This analysis does not consider the upstream supply benefits and is representative of the distribution system capability only.

Witness: E. Naczynski

UNDERTAKING JT1.4

UNDERTAKING

TR 1, page 44

To provide detail on how declining average use trend relates to expected building code stringencies and what assumptions were used in the models.

RESPONSE

As described in the response to GEC Interrogatory #13 found at Exhibit I.A1.EGD.GEC.13, the customer additions forecast is informed by projections of housing starts, interest rates, employment and other prevailing economic trends. In addition, it incorporates more granular, location-specific trends as identified through direct contact with builders, developers, and municipalities. As such, the customer additions forecast reflects the projected pool of structures, whether new construction or new service, that will require natural gas consumption. It does not incorporate effects of expected building code standards which would qualitatively apply to the structures themselves.

For purposes of the GTA Project Application, peak load estimates are used to design associated system requirements. To capture the impact of declining average use on peak hourly consumption, network analysis models used regression analysis as described in the response to Environmental Defence Interrogatory #12 found at Exhibit I.A4.EGD.ED.12. The impact of building code requirements is implicit in the resulting decline in average use. As a result, the adjusted peak hourly consumption estimates applied in the network analysis reflect the expected effect of more stringent building codes.

Witness: M. Suarez

UNDERTAKING JT1.5

UNDERTAKING

TR 1, page 50

To provide the number of TransCanada system firm transportation service contracts currently serving Enbridge CDA.

RESPONSE

Please see the response to BOMA Interrogatory #1 found at Exhibit I.A1.EGD.BOMA.1 for a list of Enbridge's existing transportation contracts with TransCanada and Union Gas as of May 2013. This includes the contract service type (i.e., FT) and primary delivery area (i.e., Enbridge CDA).

Witness: M. Giridhar

UNDERTAKING JT1.6

UNDERTAKING

TR 1, page 75

To provide further response to A1 EGD FPRO 18.

RESPONSE

There are no Enbridge internal contingency planning documents that have resulted from the meetings of the Gas Control staff referred to in the response to FRPO Interrogatory #18 found at Exhibit A1.EGD.FRPO.18. The primary purpose of these meetings is to discuss how upcoming system maintenance activities may affect respective natural gas LDC's and pipeline operators in the region. As explained in the interrogatory response, there are no written reports generated from these meetings.

Enbridge's contingency plans are specific to mitigating impacts on the downstream distribution network in the event of a supply disruption. This is explained in the response to CCC Interrogatory #2 found at Exhibit A1.EGD.CCC.2 which contains pertinent sections of the Enbridge Load Shed report. In the event of a major system outage resulting in widespread customer losses, the CGA Mutual Assistance Agreement could be called upon as a ready mechanism for Canadian natural gas industry companies to assist each other during emergencies.

In the event of an outage at the Parkway interconnect with Union on a cold winter day, the TransCanada interconnect will not be able to compensate for losses, since the capacity at this interconnect is a fraction of the Union interconnect. Also, an outage at the Parkway Union and TransCanada interconnects could occur coincidentally given that they are located in the same property.

Witness: M. Giridhar

UNDERTAKING JT1.7

UNDERTAKING

TR 1, page 76

To provide UDC cost based upon current gas supply needs if Enbridge does not obtain additional storage, Exhibit A2 EGD FRPO 26.

RESPONSE

Enbridge will file the response on or before Friday June 21, 2013 due to the data requirement associated with the response.

Witness: J. Denomy

UNDERTAKING JT1.8

UNDERTAKING

TR 1, page 80

To provide a response to FRPO A1.11(C) and 11(E)

RESPONSE

To clarify, the undertaking was to provide a response to FRPO A1.11(c) and (d) as per the June 12, 2013 transcript on page 80 at line 13.

Enbridge does not view operation of the NPS 30 Don Valley line at 480 psi as being consistent with the objectives of the application, which includes lowering the pressure of this line to 375 psi, equivalent to 30% SMYS.

In response to FRPO 11(c) - To provide the results of the network simulation with 480 psi as the operating pressure of the Don Valley pipeline.

In 2015, with Victoria Square at 480 psi (and NPS 26 at 375 psi), the pressure at Station B is 243 psi (an increase of 28 psi).

With operating pressure increases (Don Valley NPS 30 at 480 psi, NPS26 at 375 psi), Segment B could be deferred to 2019. In 2020, pressure at Station B is 223 psi.

FRPO 11(d) - To provide the results of the engineering assessment that dictates an operating pressure of 450 psi versus 480 psi and what the costs would be to overcome the limitation.

The Don Valley NPS 30 pipeline was installed in 1971 using Grade 414, 7.92mm wall thickness, with pipe of non-specified Category (as designated under CSA Z245.1).

CSA Z662-11 necessitates that, in addition to the design pressure requirements detailed in Clause 4.3.5.1, due consideration must also be given to Clause 5.2.2.3 which requires limiting the maximum hoop stress as a function of the pipe's proven energy absorption properties. As per Table 5.2 of CSA Z662-11, in the absence of positive fracture propagation control, the hoop stress of this NPS 30 (762 mm outer diameter) line is limited to a maximum of 160 MPa.

Witnesses: E. Naczynski
N. Thalassinos

Applying Clause 4.6.5, the design pressure at which operating stresses would be 160 MPa is as follows:

$$P = \frac{S_H 2t_n}{D}$$

$$P = \frac{(160{,}000\ kPa) \times 2 \times (7.92\ mm)}{762\ mm}$$

$$P = 3325\ kPa\ (482\ psig)$$

Given the NPS 30 Don Valley pipeline's age, material properties, condition, and Class 4 location, the MOP of 3,325 kPa (482 psi) is, in this case, a firm limit. For this pipeline, prudent Engineering judgment obviates the flexibility to exceed the MOP by 10% in the event of a pressure-control system failure.

A schematic of a typical Operator-Monitor configuration can be seen in the figure below. Victoria Square Gate Station would be an example of such a configuration. In order to ensure that operating pressures in excess of 3,325 kPa (482 psi) are not experienced, the monitor regulator is set at 3,325 kPa (482 psi) with the operator regulator set at 3,103 kPa (450 psi). Victoria Square Gate Station is SCADA pressure-monitored, and as such, no token relief valve is present in the installation.

The design principle of a station is that there are two regulators in series situated between isolation valves. The operating regulator controls the supply pressure at the station's set point. The function of the monitor regulator is to provide over-pressure protection in the case of a failure of the operator regulator. A second operator-monitor arrangement is typically installed in parallel to the first run to provide a backup in the event that maintenance or repair is required on the first run. In this way the supply of gas will not be interrupted to the downstream distribution system.

The difference between the station set pressure and the monitor setting is dependent on the pressure category, type of regulator, and over-pressure protection design. At Victoria Square, the regulators do not throttle constantly to hold the set pressure because this would require them to bleed constantly to atmosphere. Rather, they have fluctuation limits above and below the set point where they are allowed to throttle before they are required to operate. The 207 kPa (30 psi) differential gives room for the regulators to operate within appropriate ranges of fluctuation and also permits the SCADA monitored system, which has successive alarm limits, time to react if there is a problem without generating undue nuisance alarms.

In order to configure the Don Valley NPS 30 to operate closer to or at its MOP of 3,325 kPa (482 psi), limited options are available: installation of fracture control mechanisms, full pressure relief, or pipeline replacement.

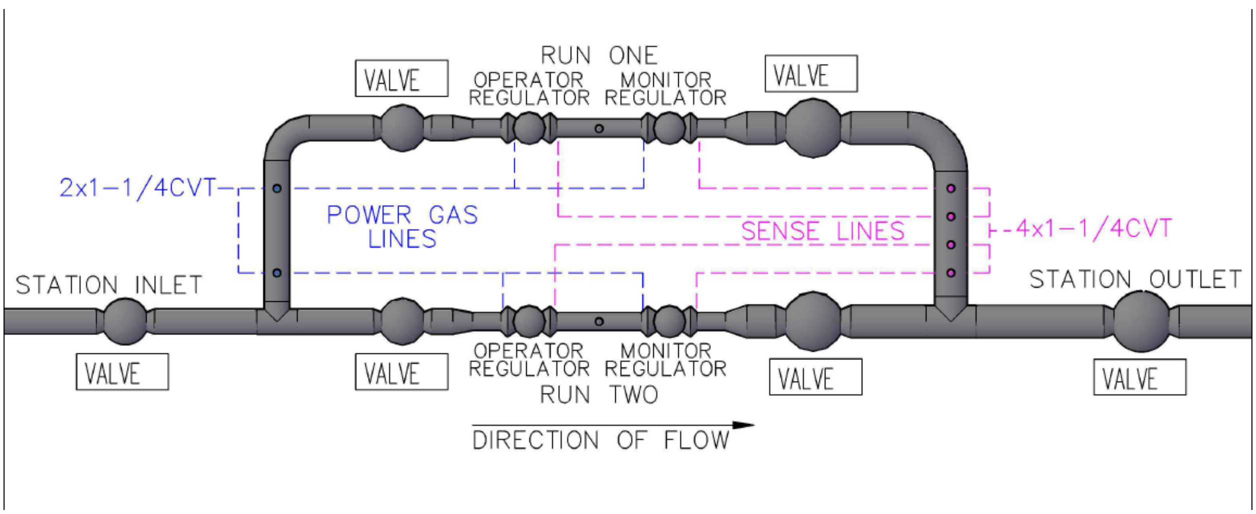
Witnesses: E. Naczynski
N. Thalassinos

Installation of fracture-arrest devices would consist of encircling rings or wraps along the pipe at intervals to restrict the flap opening during a fracturing event or installing heavier wall thickness pipe in order to reduce the hoop stress ahead of an advancing fracture front. Given the urban density along this pipe route, installation of these devices would not be suitable given that there is a possibility of a fire occurring at each arrest location.

Full pressure relief to atmosphere would present significant operating, environmental and socio-economic limitations. Impacts to customers near the station would be significant; under full relief conditions, the noise and gas volumes would be extremely disruptive. Additionally, significant volumes of natural gas would be introduced into the atmosphere.

Full replacement of the Don Valley NPS 30 would be costly and not provide the flexibility and reliability benefits associated with the proposed pipeline facilities.

Operator-Monitor Station Configuration



Witnesses: E. Naczynski
N. Thalassinos

UNDERTAKING JT1.9

UNDERTAKING

TR 1, page 86

To provide an update of Enbridge's current source of supply as a percentage

RESPONSE

Please see the response to Undertaking JT1.10.

Witness: J. Denomy

UNDERTAKING JT1.10

UNDERTAKING

TR 1, page 90

To update supply source changes from 2013 to 2016.

RESPONSE

The response to BOMA Interrogatory #5 found at Exhibit I.A1.EGD.BOMA.5 contains Enbridge's forecast of natural gas procurement by source of supply as a percentage of total supply for each of 2013 and 2016. The percentages provided in this response were calculated using projected annual supplies from each respective supply source as a percentage of total annual supply. The table below provides an expanded version of the table contained in the response to BOMA Interrogatory #5 and now includes supplies sourced in the WCSB and transported via Alliance pipeline. Supplies sourced in Chicago flow on Vector pipeline.

Supply Source As Percentage of Total Supply (Annual Percentages)	**2013**	**2016**
Western Canadian Supplies (TransCanada)	25.3%	33.6%
Western Canadian Supplies (Alliance)	8.2%	0.0%
Peaking/Seasonal	0.3%	0.1%
Ontario Production	0.0%	0.0%
Chicago Supplies (Vector)	15.8%	15.7%
Dawn Supplies	13.4%	3.7%
Niagara Supplies	0.0%	17.0%
Direct Purchase Delivery	37.9%	30.5%
Storage (Injection)/Withdrawal	-1.0%	-0.6%

The percentages for 2013 represent planned natural gas procurement for the 2013 Test Year and are consistent with the supply plan underpinning 2013 rates. The percentages for 2016 represent the current forecast of natural gas procurement for 2016.

The following provides an explanation of the changes from 2013 to 2016 for each line item contained in the table above.

Western Canadian Supplies – Supply percentages from 2013 to 2016 remain constant despite the displacement of discretionary service from the WCSB as a result of the GTA Project. The Company has assumed that it would contract for additional firm long haul transportation service with TransCanada in lieu of currently utilized discretionary service in the Enbridge EDA. The requirement to use year round long haul transport at high load factors results in a reduction in Dawn supplies. TransCanada has currently deemed additional capacity to the EDA as non-renewable past 2015. Enbridge recently requested additional firm short haul transportation service to the Enbridge EDA. This service would displace the additional long haul service to the Enbridge EDA currently assumed for 2016. For 2016 Enbridge has also assumed it would maintain some discretionary service to the Enbridge CDA. Alliance supplies are zero in 2016 as the Company has elected not to renew its contract with Alliance pipeline. This contract terminates October 31, 2015.

Peaking/Seasonal Supplies – These supplies decline from 2013 to 2016 as a result of the displacement of peaking supplies with firm short haul transportation service from Dawn and Niagara Falls once the GTA Project facilities are in service.

Ontario Production – These supplies are relatively small and are assumed to remain constant from 2013 to 2016.

Chicago Supplies – These supplies remain constant from 2013 to 2016. The Company has chosen not to renew a portion of its Vector capacity however this is offset with procurement at Chicago as a result of the non-renewal of the Alliance contract.

Dawn Supplies – These supplies decrease from 2013 to 2016 as a result of procurement at Niagara Falls once the GTA Project facilities are in service, the assumption of increased long haul transportation service discussed above and an assumed decline in degree days. While Enbridge's procurement of supplies at Dawn is assumed to decrease, this decrease is offset by the assumption that Direct Purchase customers will be able to procure gas at Dawn via the new delivery point service offering from Enbridge once GTA Project facilities are in service. The request for additional short haul service to the Enbridge EDA would increase procurement at Dawn if this service becomes available.

Niagara Supplies – Niagara supplies are assumed to increase from 2013 to 2016 with the GTA Project facilities in service in accordance with the MOU with TransCanada.

Direct Purchase Delivery – The change in Direct Purchase supplies is largely due to timing differences and the assumptions used to derive each forecast. The Direct Purchase projections for 2013 were developed in 2011 and updated and approved in

2012. The Direct Purchase projections for 2016 were developed more recently in 2013. The primary reason for the reduction in Direct Purchase deliveries is a reduction in degree days from 2013 to 2016. Migration from Direct Purchase to system gas is also assumed over this period. While Direct Purchase deliveries are projected to decline from 2013 to 2016, the 2016 projection assumes increased Direct Purchase procurement at Dawn through the new delivery point service offering contemplated with the GTA Project facilities in service. This new delivery point service offering will also increase security of supply for the Enbridge CDA.

With the market for upstream transportation service evolving rapidly Enbridge will continue to work with its upstream business partners in order to ensure the needs of its customers are met. The Company intends to continue to update its gas plan annually in order to reflect changes in its gas supply portfolio.

UNDERTAKING JT1.11

UNDERTAKING

TR 1, page 102

To provide how much growth can go through Station B in 2015

RESPONSE

To clarify, the Company understands the question to be how much of the forecasted load growth to 2025 (correction from 2050 in transcript) of approximately 190,000 GJ/d in the project area would be required to go through Station B.

By 2025, approximately 15 TJ/d of growth will have been added at Station B.

Witness: E. Naczynski

UNDERTAKING JT1.12

UNDERTAKING

TR 1, page 110

To provide costs used to review the Lakeshore or Lake Ontario alternatives as compared to proposals

RESPONSE

As described in Alternatives, Exhibit A, Tab 3, Schedule 7, the Company looked at southern routing to reinforce the XHP grid to Station B.

A scenario of building a NPS 36 from Parkway West to Station B, running south along Highway 407, east along the QEW, and then along Lake Shore Boulevard was considered. The desktop costing of this scenario is $950 million, but does not include IDC or escalation. This scenario would alleviate the minimum system pressure constraint, and would allow the Gas Supply benefits to be achieved.

A scenario of twinning the NPS 24 from the termination of the NPS 36 MSL line to West Mall Station with a NPS 24 line and then paralleling the NPS 20 Lake Shore line from West Mall Station to Station B with a NPS 36 pipeline was considered. The desktop costing of this scenario is $590 million, but does not include IDC or escalation. This scenario would alleviate the minimum system pressure constraint, but would not allow all of the Gas Supply benefits to be achieved due to capacity being constrained upstream on the NPS 36 MSL line from Parkway.

With respect to the NPS 20 line along Lake Shore Boulevard, in either of the above scenarios, the pipeline may be abandoned along the paralleled sections. However, this would involve numerous pressure regulation stations and localized piping in order to provide appropriate pressure into the HP grid and service lines currently fed from the NPS 20 line. The incremental costs are not included in the above estimates.

Timing in both scenarios was a concern, due to the urban nature. Multiple constraints would likely arise that could not be identified with a desktop study. Routing changes due to constraints could substantially impact the costs. Other socio-economic factors that impact stakeholders, such as traffic disruption, construction noise, dust, etc. also need to be considered. There would be considerable risk of encountering suspect soils along these routes, and additional costs would be incurred for handling of any suspect soils encountered. These routes also have future potential for being impacted by other large infrastructure projects, examples being a tunnel to the island or the moving of the Gardiner Expressway. If relocation of a section of mains is required in the future, franchise agreements require sharing of the cost between the utility and the City. A routing with an easement in a utility corridor does not have the same level of future risk for relocation costs to be incurred.

Scenarios were examined that included a submarine pipeline routing through Lake Ontario, with a landfall south of Station B and connecting to Station B. These scenarios were screened out due to the long lead times expected with permitting, contracting specialized resources, and timing windows that would be anticipated for construction. The Company did not believe this could be in service prior to 2017. Costs, and particularly uncertainty of costs, both construction and maintenance, were also reasons why these routes were screened out of the process.

UNDERTAKING JT1.13

UNDERTAKING

TR 1, page 111

Is an update of Lakeshore in EGD's 10-year plan?

RESPONSE

A large scale replacement of the NPS 20 that runs along Lakeshore Boulevard is not currently in the Asset Plan. However, a short section of size for size replacement is planned on the outlet of Station B. The Asset Plan is a rolling ten year plan, so this may be included in the future as distribution system integrity studies are conducted.

Witness: E. Naczynski

UNDERTAKING JTX2.1

UNDERTAKING

TR 2, page 115

To verify capital savings amounts

RESPONSE

The response was filed in confidence with the Board. Parties who signed a Declaration and Undertaking will also receive copies.

Witness: T. Horton

UNDERTAKING JT2.10

UNDERTAKING

TR 2, page 75

To inquire whether Global Insights inflation data can be released. If yes provide under confidence.

RESPONSE

The response was filed in confidence with the Board. Parties who signed a Declaration and Undertaking will also receive copies.

Witness: T. Horton

UNDERTAKING JT2.11

UNDERTAKING

TR 2, page 80

To confirm where gas cost savings are included in board staff 48 in transportation savings and distribution revenues.

RESPONSE

The gas cost savings or expected gas supply benefits resulting from the GTA Project are included in the Line item entitled "Total Transportation Savings" in the response to Board Staff Interrogatory #48 found at Exhibit I.D5.EGD.STAFF.48, Attachment 1, pages 2-5, Line 18.

The expected gas supply benefits compare the total cost of landing natural gas in the Enbridge franchise area from different supply points. Included in this cost comparison are total costs related to tolls, fuel, and commodity procurement. An explanation of the expected gas supply benefits calculation can be found at Exhibit A, Tab 3, Schedule 5, pages 28 to 30. The Attachment to Exhibit A, Tab 3, Schedule 5 contains the assumptions underpinning the expected gas supply benefits calculations.

Please refer to the response to Undertaking JT2.16 for an update to the expected gas supply benefits calculations resulting from the National Energy Board's final decision related to TransCanada's tolls to be implemented on July 1st, 2013.

The Gas Distribution Revenues and Gas Costs as found in response to Board Staff Interrogatory #48 at Exhibit I.D5.EGD.STAFF.48, Attachment 1, pages 2-5, Lines 16 and 19, respectively, exclude commodity. Together, these values represent the forecasted delivery revenue associated with the ten years of customer additions incremental to the project. The distribution rates and gas cost rates that underpin these forecasts are held constant in current year terms for the feasibility calculation. This is consistent with past LTC applications. The rates used were approved at EB-2013-0045.

Witnesses: J. Denomy
S. Murray

UNDERTAKING JT2.12

UNDERTAKING

TR 2, page 88

To provide reference to where EGD's economic model identifies gas cost savings. If there is no reference, provide analysis of how gas costs have been included in EGD's economic mode

RESPONSE

Please see the response to Undertaking JT2.11.

Witness: J. Denomy

UNDERTAKING JT2.13

UNDERTAKING

TR 2, page 94

To run economic sensitivity analysis removing and including the transportation service charge and confirm direct purchase is included.

RESPONSE

Please see the table provided on the following page. The Company has provided: item 12(a)(ii), updated 12(b) to include items (i) through (vi) and provided 12(b) excluding the transportation services charge. In the context of the technical conference discussion, the Company interpreted the request confirming the inclusion of direct purchase as the update of 12(b) to include items (i) through (vi).

Note, the Company held the transportation savings in scenario 12(b) (Col. 9 below), per the description provided in footnote 6. However, this scenario would imply EGD Sole Use of the Shared Pipeline and as such higher transportation savings would be expected.

JT2.15 has also been included in the table below.

Witnesses: J. Denomy
S. Murray

SUMMARY OF INPUTS	Col. 1	Col. 2	JT2.13 Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	JT2.13 Col. 8	JT2.13 Col. 9	JT2.15 Col. 10
	Base Case 36" Shared	A.2-CCC-12(a)(i) 10% increase in Capital	A.2-CCC-12(a)(ii) 10% reduction in Commodity Prices	A.2-CCC-12(a)(iii) 10% reduction in Transp. Savings	A.2-CCC-12(a)(iv) 0.5% reduction in Annual Volumes	A.2-CCC-12(a)(v) Remove Transp. Servic Charge after Yr. 15	A.2-CCC-12(a)(vi) April 15 filing transportation assumpt.	A.2-CCC-12(b) Combination of (i) through (vi) (with Transpt Services Charge)	A.2-CCC-12(b) Combination of (i) through (vi) (without Transpt Services Charge)	A.2-CCC-12(a)(v) Remove Transp. Service Charge completely
Capital Investment										
Total Upfront Capital	$554,575,341	$610,032,875	$554,575,341	$554,575,341	$554,575,341	$554,575,341	$554,575,341	$610,032,875	$610,032,875	$554,575,341
Future Reinforcement Projects										
2017	$21,000,000	$23,100,000	$21,000,000	$21,000,000	$21,000,000	$21,000,000	$21,000,000	$23,100,000	$23,100,000	$21,000,000
2018	$16,400,000	$18,040,000	$16,400,000	$16,400,000	$16,400,000	$16,400,000	$16,400,000	$18,040,000	$18,040,000	$16,400,000
2019	$13,000,000	$14,300,000	$13,000,000	$13,000,000	$13,000,000	$13,000,000	$13,000,000	$14,300,000	$14,300,000	$13,000,000
2020	$250,000	$275,000	$250,000	$250,000	$250,000	$250,000	$250,000	$275,000	$275,000	$250,000
Capital Maintenance Costs[1]	$5,218,238	$5,740,062	$5,218,238	$5,218,238	$5,218,238	$5,218,238	$5,218,238	$5,740,062	$5,740,062	$5,218,238
Services[2]	$379,533,696	$417,487,066	$379,533,696	$379,533,696	$379,533,696	$379,533,696	$379,533,696	$417,487,066	$417,487,066	$379,533,696
Total Capital	$989,977,275	$1,088,975,003	$989,977,275	$989,977,275	$989,977,275	$989,977,275	$989,977,275	$1,088,975,003	$1,088,975,003	$989,977,275
Total Distribution Revenues	$4,546,724,222	4,546,724,222	4,546,724,222	$4,546,724,222	$4,147,019,522	$4,546,724,222	$4,546,724,222	$4,147,019,522	$4,147,019,522	$4,546,724,222
Total Transportation Savings[1,3]	$1,632,014,615	$1,632,014,615	$1,702,525,105 [5]	$1,468,813,153	$1,632,014,615	$1,632,014,615	$392,136,859	$1,532,272,595 [6]	$1,532,272,595 [6]	$1,632,014,615
Total Transportation Services Charge[1,4]	$277,595,905	$304,607,380	$277,595,905	$277,595,905	$277,595,905	$152,102,980	$277,595,905	$304,607,380	$0	$0
Total Customer Additions (2015 - 2024)	146,337	146,337	146,337	146,337	146,337	146,337	146,337	146,337	146,337	146,337
Total Volumes (10^3m^3)[1]	24,709,032	24,709,032	24,709,032	24,709,032	22,537,605	24,709,032	24,709,032	22,537,605	22,537,605	24,709,032
SUMMARY OF RESULTS										
Net Present Value (40 years)	$633,574,507	$568,512,325	$668,384,094	$553,041,440	$592,612,955	$609,619,381	$22,547,856	$478,346,335	$376,560,441	$540,868,702
Profitability Index (40 years)	1.77	1.63	1.81	1.67	1.72	1.74	1.03	1.53	1.42	1.66

[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).
[4] Charges to be paid by TransCanada for use of the Shared Pipeline from Bram West Interconnect to Albion Road Station.
[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 transportation savings based on $1,702.5MM.

UNDERTAKING JT2.14

UNDERTAKING

TR 2, page 95

To provide sensitivity analysis for both a combined 42 and 36 inch pipe with same assumptions included in each for comparison purposes.

RESPONSE

Please see the table on the following page.

Note: the Transportation Services Charge for the 42" scenario and 36'' scenario is based on TransCanada's share of the Shared Pipeline, at 60% and 50%, respectively.

Witness: S. Murray

SUMMARY OF INPUTS	42" with transportation service charge	36" with transportation service charge	42" without transportation service charge	36" without transportation service charge
Capital Investment				
Total Upfront Capital	$595,280,523	$554,575,341	$595,280,523	$554,575,341
Future Reinforcement Projects				
2017	$21,000,000	$21,000,000	$21,000,000	$21,000,000
2018	$16,400,000	$16,400,000	$16,400,000	$16,400,000
2019	$13,000,000	$13,000,000	$13,000,000	$13,000,000
2020	$250,000	$250,000	$250,000	$250,000
Capital Maintenance Costs[1]	$5,218,238	$5,218,238	$5,218,238	$5,218,238
Services[2]	$379,533,696	$379,533,696	$379,533,696	$379,533,696
Total Capital	$1,030,682,457	$989,977,275	$1,030,682,457	$989,977,275
Total Transportation Savings[1,3]	$1,632,014,615	$1,632,014,615	$1,632,014,615	$1,632,014,615
Total Transportation Services Charge[1,4]	$388,604,339	$277,595,905	$0	$0
Total Distribution Revenues[1]	$4,546,724,222	$4,546,724,222	$4,546,724,222	$4,546,724,222
Total Customer Additions (2015 - 2024)	146,337	146,337	146,337	146,337

SUMMARY OF RESULTS

Net Present Value (40 years)	$637,855,721	$633,574,507	$507,372,361	$540,868,702
Profitability Index (40 years)	1.74	1.77	1.59	1.66

[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).

[4]Charges to be paid by TransCanada for use of the Shared Pipeline from Bram West Interconnect to Albion Road Station.

Witness: S. Murray

UNDERTAKING JT2.15

UNDERTAKING

TR 2, page 97

To run sensitivity analysis of not having revenue stream from TCPL for comparison purposes

RESPONSE

Please see table in the response to undertaking JT2.14.

Witness: S. Murray

UNDERTAKING JT2.16

UNDERTAKING

TR 2, page 99

To verify that table in reply to STAFF 14 is accurate and if necessary update.

RESPONSE

The response to Board Staff Interrogatory #14 found at Exhibit I.A3.EGD.STAFF.14 is accurate if it is assumed that the tolls from TransCanada's Review Application are utilized to calculate the expected gas supply benefits.

Please note that in conjunction with filing the Review Application, TransCanada, as directed by the National Energy Board in its RH-003-2011 Decision, also filed its Compliance Filing. The Compliance Filing contains the tolls that would prevail pursuant to implementation of the National Energy Board's Decision in RH-003-2011.

On June 11, 2013 the National Energy Board dismissed TransCanada's Review Application in its entirety and in Toll Order TG-006-2013 directed TransCanada to charge, on a final basis effective July 1, 2013, its Compliance Filing tolls.

The table below provides an updated response to Board Staff Interrogatory #14 found at Exhibit I.A3.EGD.STAFF.14. The scenarios contained in the table utilize the expected gas supply benefits calculated using TransCanada's Compliance Filing tolls as the baseline.

Witnesses: J. Denomy
S. Murray

($ Millions)	Base Case	Transportation Savings Sensitivity				
		100%	75%	50%	25%	0%
GTA pipeline Capital	$554.6	$554.6	$554.6	$554.6	$554.6	$554.6
Total transportation savings[1]	$1,465.1	$1,465.1	$1,098.8	$732.5	$366.3	$0.0
Total transportation service charge[2]	$277.6	$277.6	$277.6	$277.6	$277.6	$277.6
Summary of Results:						
Net Present Value (40 years)	$551.2	$551.2	$370.5	$189.7	$9.0	($171.8)
Profitability Index (40 years)	1.67	1.67	1.45	1.23	1.01	0.79

Notes:
1. 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).
2. Charges to be paid by TransCanada for use of the Shared Pipeline from Bram West Interconnect to Albion Road Station.

The response to Board Staff Interrogatory #11 found at Exhibit I.A1.EGD.STAFF.11 provides the expected gas supply benefits if the tolls from TransCanada's Compliance Filing are used. The expected gas supply benefits in the response to Board Staff #11 correspond to the base case expected gas supply benefits in the table above.

In order to provide a complete record the Company is also providing in this undertaking response updated tables for the expected gas supply benefits calculations utilizing final tolls for the TransCanada Mainline.

Below are the tables that underpin the calculation requested at Board Staff Interrogatory #11 found at Exhibit I.A1.EGD.STAFF.11, i.e., the expected gas supply benefits resulting from the NEB Decision in RH-003-2011. Provided below are Tables A1 to A4 contained in the Attachment to Exhibit A, Tab 3, Schedule 5. Tables A1 to A3 contain the toll, fuel ratio, and commodity price assumptions. Table A4 contains the expected gas supply benefits calculations. The tolls for Niagara Falls to Enbridge Parkway CDA and Parkway to Bram West CDA were provided by TransCanada and derived using the cost and billing determinant information contained in the Compliance Filing.

Witnesses: J. Denomy
S. Murray

Table A1: Toll Assumptions

Toll Assumptions	Demand Toll ($/GJ)	Commodity Toll ($/GJ)
FT Empress-EGD CDA[1]	1.566	0.000
Dawn-EGD CDA[1]	0.236	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]	0.153	0.000
Union Parkway Belt-Bram West CDA[4]	0.088	0.000

[1] 2013-2017 Final Mainline tolls per TransCanada's Compliance Filing.
[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 Toll provided by TransCanada. Toll based on costs and billing determinants contained in TransCanada's Compliance Filing.

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	4.64
2016	3.85	4.44	4.40	5.62	4.68
2017	4.02	4.57	4.55	5.77	4.81
2018	4.42	4.75	4.72	5.95	4.98
2019	4.47	4.94	5.01	6.00	5.18
2020	4.52	5.03	5.08	6.05	5.26
2021	4.56	5.07	5.12	6.09	5.30
2022	4.60	5.10	5.16	6.12	5.34
2023	4.64	5.15	5.20	6.17	5.38
2024	4.68	5.15	5.24	6.21	5.39
2025	4.72	5.19	5.28	6.24	5.42

[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	28.1	168.8	168.3	168.3	168.3	168.8	168.3	168.3	168.3	168.8	168.3
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	99.4	594.9	612.1	655.5	661.4	668.6	671.3	675.4	680.3	686.6	688.5
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	7.4
Service	TCPL FT - Direct Pruchase	Demand Charges	15.7	94.1	93.8	93.8	93.8	94.1	93.8	93.8	93.8	94.1	93.8
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	65.4	391.2	402.3	428.2	434.4	439.8	441.6	444.4	447.6	451.3	452.7
		A-Total Cost	164.9	993.3	1,021.6	1,091.2	1,102.9	1,115.7	1,120.2	1,127.2	1,135.3	1,145.4	1,148.7
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	1.9	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
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	55.5	333.8	343.7	356.5	377.6	384.2	386.0	388.7	391.8	395.8	397.3
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-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	4.3	25.8	25.7	25.7	25.7	25.8	25.7	25.7	25.7	25.8	25.7
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	4.4	26.3	26.3	26.3	26.3	26.4	26.3	26.3	26.3	26.4	26.3
		B-Total Cost	143.4	860.8	883.5	915.3	957.9	975.3	979.8	986.5	994.4	1,000.4	1,004.0
		Savings (A-B)	21.5	132.5	138.1	175.9	145.0	140.4	140.3	140.7	141.0	144.9	144.7

UNDERTAKING JT2.17

UNDERTAKING

TR 2, page 108

Related to BOMA A1- IR25 Table Part D (capacity deficit), to Provide a similar capacity number for the 41 degree day extreme situation.

RESPONSE

At a 41 Degree Day ("DD"), in 2013, the capacity deficit at Station B is approximately 4 TJ/day, and in 2014, the capacity deficit at Station B is approximately 7 TJ/day.

Witness: E. Naczynski

UNDERTAKING JT2.18

UNDERTAKING

TR 2, page 110

To calculate percentage reduction in demand required to Lower pipeline pressure at both 5% and 10% for comparison purposes.

RESPONSE

Analysis for this response was completed in 2015, at DD 41, absent of any reinforcement and without operating pressure reductions. The load reductions were taken at each district station within the Victoria Square influence area as defined at Exhibit A, Tab 3, Schedule 3, Figure 3 (i.e., the "peach area"). No load reductions were taken on the four large fixed contract demands within this area.

With a load reduction of 5%, pressure at Station B rises from 215 psi to 228 psi; the load in the area fed by Victoria Square was decreased by approximately 29 TJ/day. With a load reduction of 10%, pressure at Station B rises from 215 psi to 239 psi; the load in the area fed by Victoria Square was decreased by approximately 57 TJ/day.

Witness: E. Naczynski

UNDERTAKING JT2.19

UNDERTAKING

TR 2, page 120

2006 growth study and growth rate at that time and forecast for the next 20 years in 2006.

RESPONSE

The table below shows the 2006 distribution system planning forecast for the next ten years for peak hourly load growth. The Company's forecast at that time did not go beyond ten years.

Table 1: 2006 Forecast Growth Loads

	Forecast Peak Hour Growth (10^3m^3/hr)										
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
TOTAL	125	72	69	63	63	64	42	41	41	41	41

The above table includes a slightly larger area than the GTA Project Influence Area. The Municipalities included: Etobicoke-York, North York, Scarborough, Toronto-East York, Richmond Hill, Markham, Vaughan, Brampton, and Mississauga.

Witness: E. Naczynski

UNDERTAKING JT2.20

UNDERTAKING

TR 2, page 123

To advise TRC net benefits with 9TJ/day GTA growth.

RESPONSE

Please see below a revised chart outlining the illustrative dollar value that would be required to be deployed within the GTA in order to offset growth in the GTA Project Influence Area through increased DSM.

This chart also includes the estimated net TRC benefits that would be associated with this increased DSM activity assuming that the cost-effectiveness of increased DSM in GTA was entirely static. The additional net TRC benefits of $140.6M are incremental to the "base case" DSM activities in the GTA Project Influence Area and the rest of the franchise.

It is the Company's view that additional DSM of the magnitude contemplated in this illustration would generate less cost-effective results than those currently achieved through Enbridge's DSM activities.

DSM Required to Offset Growth in the GTA Project Influence Area		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total GTA DSM Budget Needed	Yearly	$49,554,431	$50,545,520	$51,556,430	$52,587,559	$53,639,310	$54,712,096	$55,806,338	$56,922,465	$58,060,914	$59,222,132	$60,406,575	$61,614,707
	Cumulatively	$49,554,431	$100,099,951	$151,656,381	$204,243,940	$257,883,250	$312,595,346	$368,401,684	$425,324,149	$483,385,063	$542,607,195	$603,013,771	$664,628,477
Additional Net TRC Benefits		$140,654,152	$140,654,152	$140,654,152	$140,654,152	$140,654,152	$140,654,152	$140,654,152	$140,654,152	$140,654,152	$140,654,152	$140,654,152	$140,654,152
Total Franchise-wide Net TRC Benefits		$278,123,650	$278,123,650	$278,123,650	$278,123,650	$278,123,650	$278,123,650	$278,123,650	$278,123,650	$278,123,650	$278,123,650	$278,123,650	$278,123,650

Witnesses: T. MacLean
F. Oliver-Glasford
J. Ramsay

UNDERTAKING JT2.21

UNDERTAKING

TR 2, page 125

2013/2014 projected TRC screening ratios

RESPONSE

Enbridge will provide the Intervenor with the electronic spreadsheet in confidence under the signed Declaration and Undertaking.

Please note that the Custom project value is based off historical averages and reasonable assumptions about the market. It is privy to uncertainty and was used for illustrative purposes in planning.

Witnesses: T. MacLean
F. Oliver-Glasford
J. Ramsay

UNDERTAKING JT2.22

UNDERTAKING

TR 2, page 125

EX1 A4 GEC34 – expected cubic metre sales by customer type.

RESPONSE

Please refer to the response to Undertaking JT2.36 described in relation to Environmental Defence Interrogatory #8.

Witnesses: T. MacLean
F. Oliver-Glasford
J. Ramsay

UNDERTAKING JT2.23

UNDERTAKING

TR 2, page 126

Average measure life for all DSM programs.

RESPONSE

Please see below the weighted and unweighted average measure lives for each year from 2008 to 2012 inclusive. Due to the level of effort required to complete this analysis and the stringent timelines requested by intervenors, Enbridge is not able to provide this data from 2003 to 2013 without expending an inordinate amount of effort.

	2008	2009	2010	2011	2012
Unweighted	14.36	14.23	15.60	17.08	17.71
Weighted	12.01	14.88	14.73	16.46	17.79

Witnesses: T. MacLean
F. Oliver-Glasford
J. Ramsay

UNDERTAKING JT2.24

UNDERTAKING

TR 2, page 129

To advise which 2012 DSM measures affect both peak and annual savings.

RESPONSE

The table below lists our DSM technologies and a notional review of whether they may in fact increase peak load. As stated in the response to GEC Interrogatory #35 found at Exhibit I.A4.EGD.GEC.35, "Enbridge does not actively track or calculate the impact on peak hour of specific DSM measures." In the table below only a handful of technologies have been identified as potentially increasing peak demand (based on what is known about their general operating profile) even though they decrease overall annual load. The other technologies, listed as "no", were anticipated by our technical experts to decrease both peak and annual loads.

Notional Impact of Technology on Peak Load	
Technology	**NG Peak Hour Profile May Coincide with Technology's Operating Profile**
Aerator	No
Air Curtain	No
Air Doors	No
Air Handling Unit	No
Boiler - Hydronic Condensing - Advanceme	No
Boiler - Hydronic Condensing - Replaceme	No
Boiler - Hydronic High Efficiency	No
Boiler - Hydronic High Efficiency - Adva	No
Boiler - Hydronic High Efficiency - Repl	No
Boiler - Steam - Advancement	No
Boiler - Steam - Replacement	No
Building Envelope	No
Burner	No
Condensing Boiler	No
Condensing Economizer	No
Controls	*Perhaps*

Witnesses: T. MacLean
F. Oliver-Glasford
J. Ramsay

Notional Impact of Technology on Peak Load	
Technology	**NG Peak Hour Profile May Coincide with Technology's Operating Profile**
Demand Control Ventilation (Optimization)	No
Demand Control Ventilation (Occupancy based)	*Perhaps*
Destratification	No
Direct Contact Water Heater - Advancemen	No
Drain Water Heat Recovery	No
Economizer	No
Energy Star	No
Energy Star Broiler	No
Energy Star Dishwasher	No
Energy Star Fryer	No
Energy Star Rack Conveyor	No
Energy Star Stationary Rack	No
ERV	No
ERV/HRV	No
Front Load washer	No
Furnace	No
Greenhouse Curtains	No
Heat Recovery	No
HRV	No
Industrial Equipment	No
Infrared	No
Insulation	No
Insulation/Caulking/Sealing	No
Kitchen Ventilation	No
Linkageless Control	No
Make Up Air Unit	No
Operational Improvements	No
Oven	No
Ozone Laundry	No
Pipe Insulation	No
Pre-Rinse Spray Nozzle	No
Reflective Panel	No
Roof Top Unit	No

Witnesses: T. MacLean
F. Oliver-Glasford
J. Ramsay

Notional Impact of Technology on Peak Load	
Technology	**NG Peak Hour Profile May Coincide with Technology's Operating Profile**
Showerhead	No
Showerheads	No
Small Commercial High Eff Boiler	No
Steam Trap	No
Tankless	No
Thermostat - Programmable (Commercial)	*Perhaps*
Thermostat - Programmable (Residential)	*Yes*
VFD	No
Waste Water Reduction	No

Witnesses: T. MacLean
F. Oliver-Glasford
J. Ramsay

UNDERTAKING JT2.25

UNDERTAKING

TR 2, page 139

To respond to FRPO hard copy questions sent to EGD.

RESPONSE

As discussed in the transcript (June 13, 2013) on page 139, lines 2 to 4, Enbridge will file the responses to FRPO's questions on or before Friday June 21, 2013.

Witness: E. Naczynski

UNDERTAKING JT2.26

UNDERTAKING

TR 2, page 145

To provide average peak load per sector.

RESPONSE

See the table provided on the following page for peak hourly consumption by sector and year, averaged across all municipalities within the project influence area.

Witness: E. Naczynski

Average Peak Hourly Consumption (m3/hr)																				
	Derived Historical						Forecast													
Sector	2006-2007	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026
Apartment	86.26	86.50	84.90	83.44	83.92	85.89	92.35	86.91	91.77	91.44	90.86	89.50	89.08	88.78	88.44	88.10	88.10	88.10	88.10	88.10
Commercial	9.60	9.64	9.74	9.63	9.47	11.76	10.07	9.51	9.51	9.45	9.38	9.30	9.27	9.24	9.22	9.19	9.19	9.19	9.19	9.19
Industrial	57.77	59.18	57.66	54.55	55.56	37.63	41.95	38.25	55.26	54.88	23.96	36.62	36.23	35.86	35.51	35.18	35.18	35.18	35.18	35.18
Residential	1.50	1.50	1.47	1.44	1.41	1.34	1.35	1.35	1.34	1.34	1.34	1.33	1.33	1.32	1.32	1.32	1.32	1.32	1.32	1.32

UNDERTAKING JT2.27

UNDERTAKING

TR 2, page 149

To provide declining average use trends per customer and per sector. Include equation used for regression

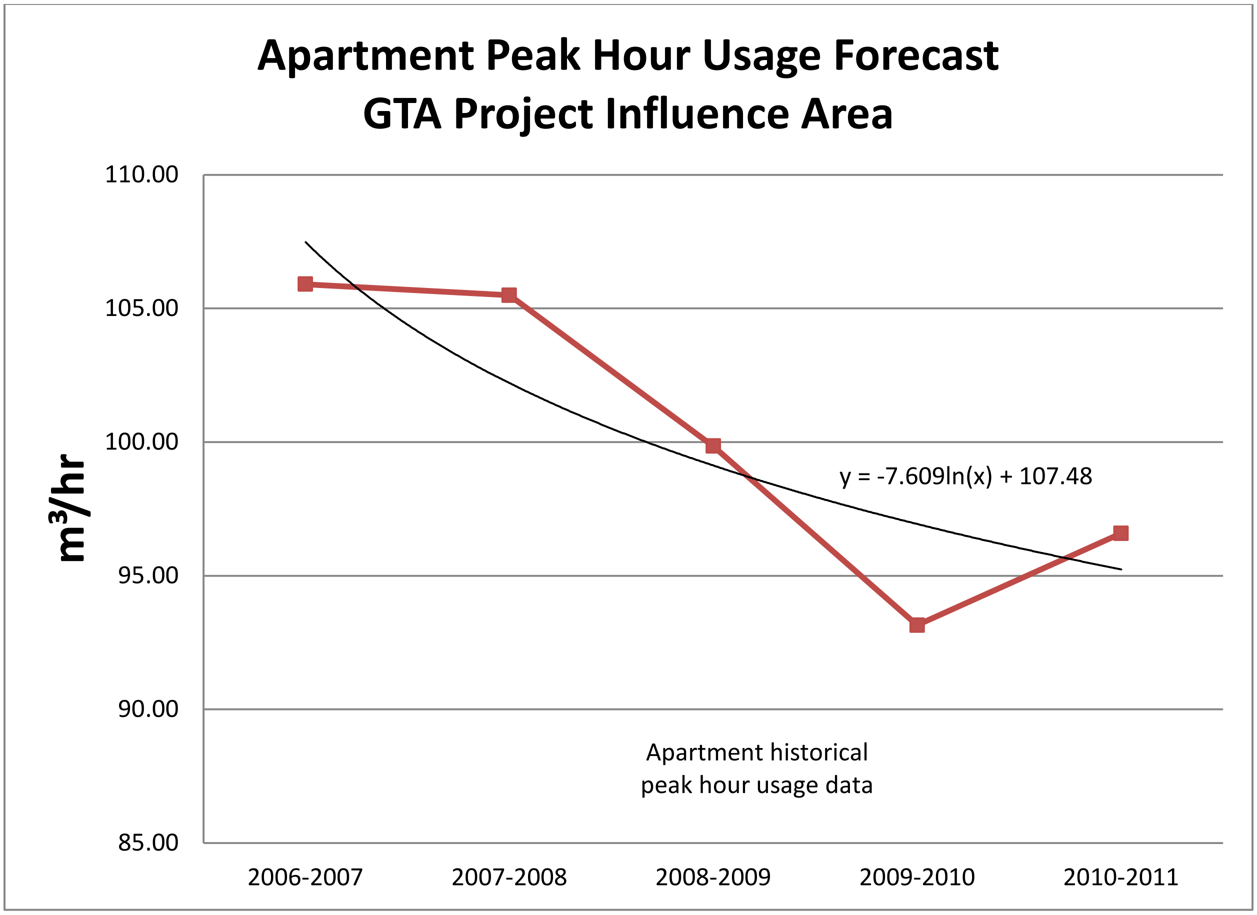
RESPONSE

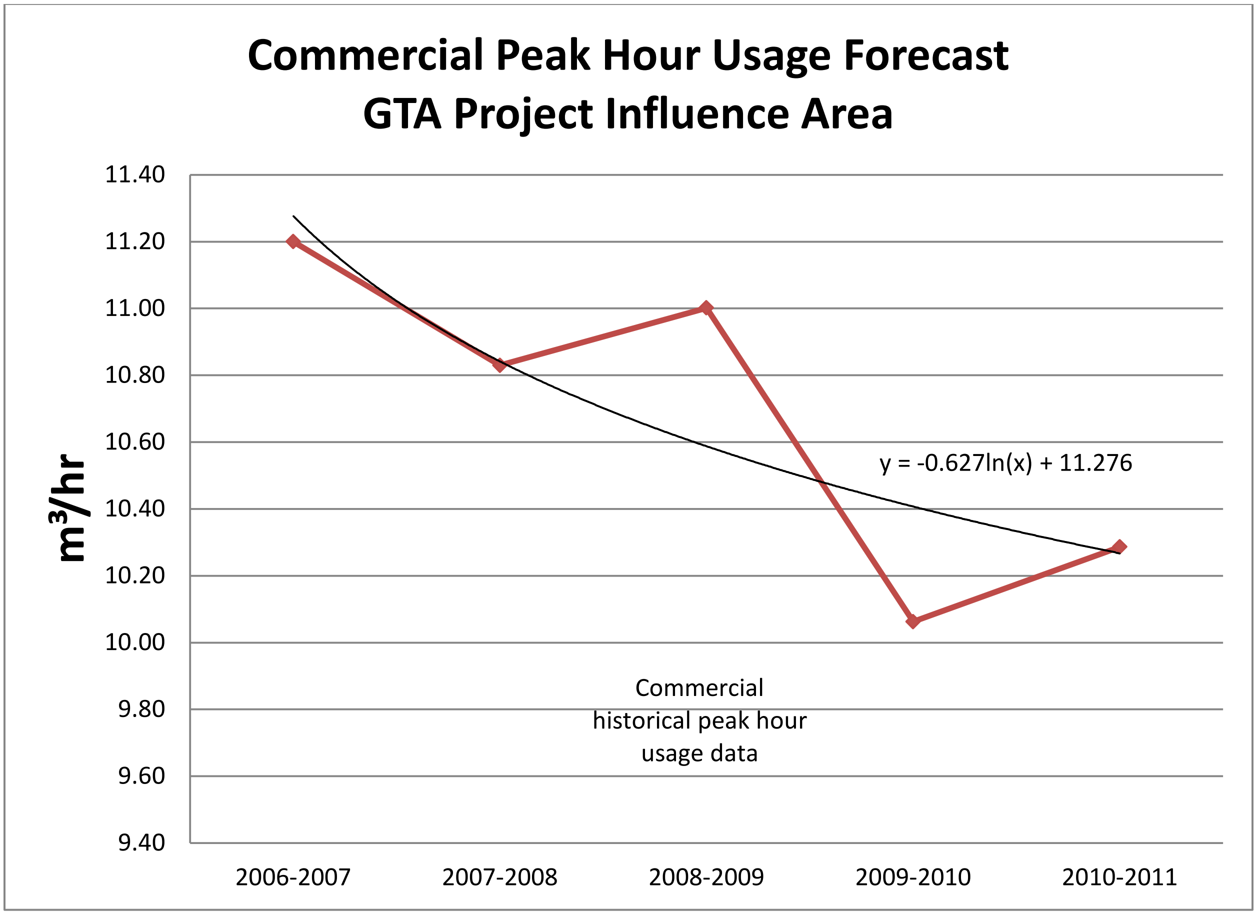
The figures provided on the following pages illustrate the declining peak average usage trends for each sector. The average peak hourly usage forecast was prepared by collecting five years of load gathering data and using lograrithmic trend lines.

5 years historical data: *2006, 2007, 2008, 2009, 2010*
4 types of customers: *Apartment, Commercial, Industrial, Residential*

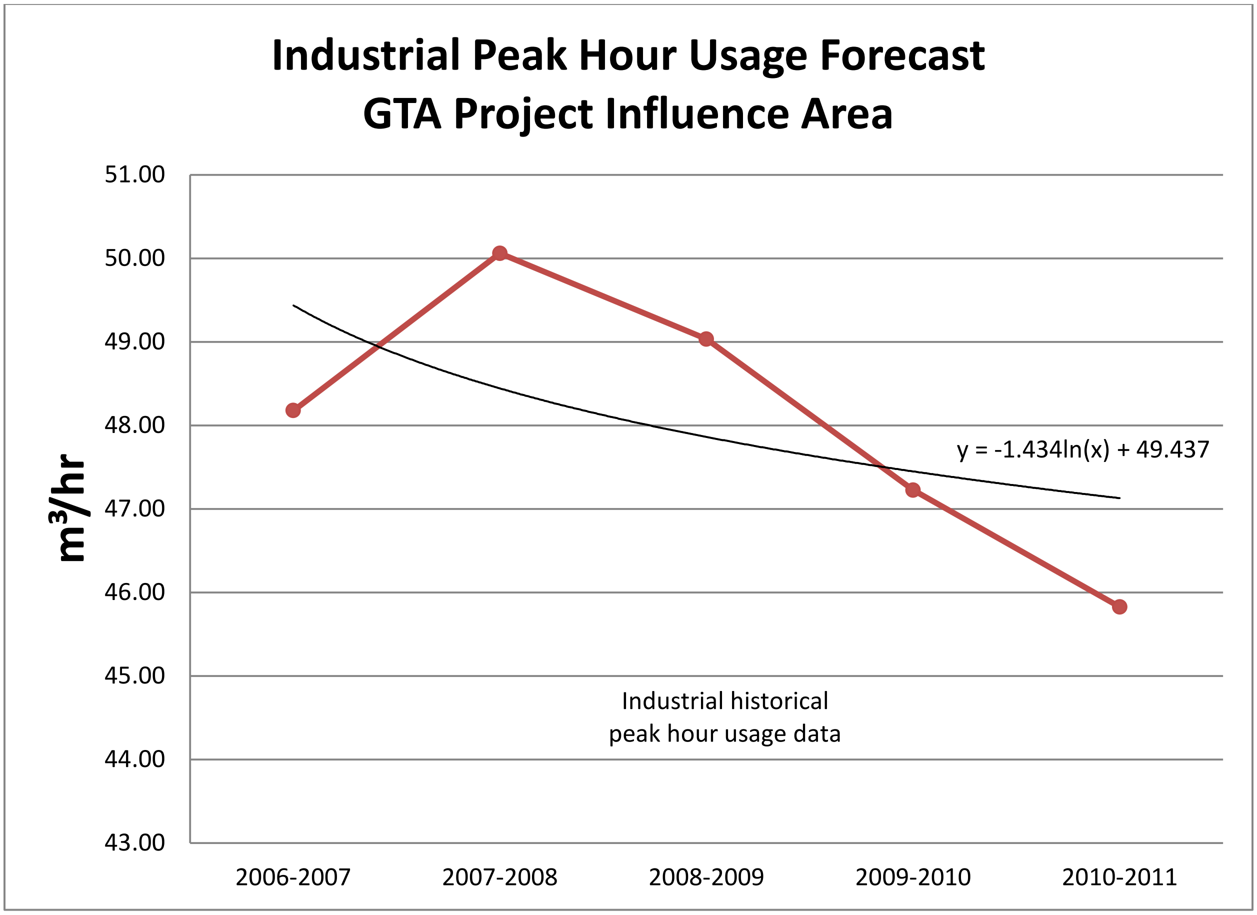
Data has only been provided for 2006 to 2010 as Enbridge implemented a new load gathering system. Prior to 2004, load gathering was completed on a legacy main frame system and the archived data is not readily accessible. From 2004 to 2006 there were numerous changes in customer classifications which make year to year comparisons irrelevant due to changing base data. The load presented excludes unbundled customers. A description of the load gathering process for network planning purposes can be found in the response to Environmental Defence Interrogatory #12 found at Exhibit I.A4.EGD.ED.12.

Witness: E. Naczynski

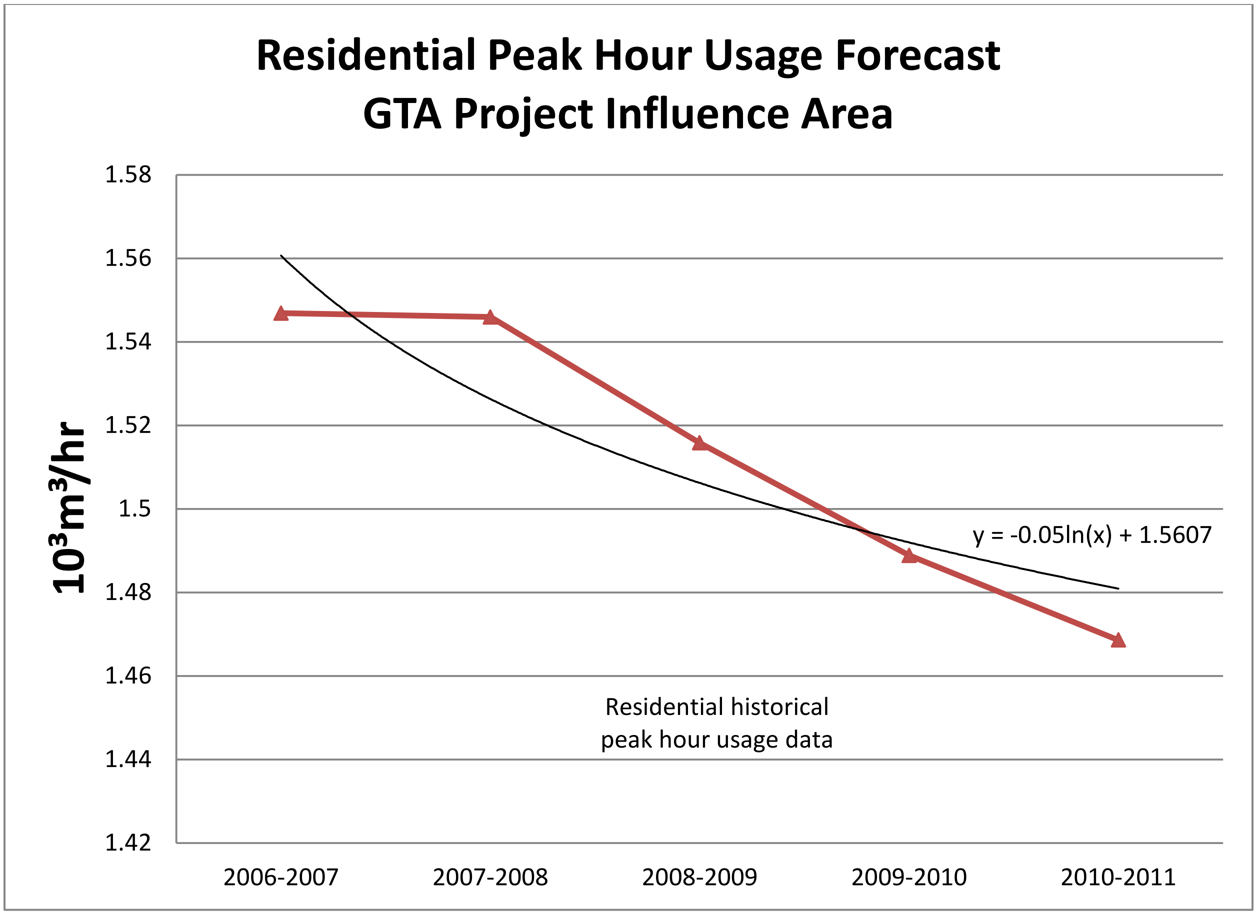

Apartment Peak Hour Usage Forecast
GTA Project Influence Area
110.00
105.00
100.00
95.00
90.00
85.00
m³/hr
y = -7.609ln(x) + 107.48
Apartment historical
peak hour usage data
2006-2007
2007-2008
2008-2009
2009-2010
2010-2011



Witness: E. Naczynski



Witness: E. Naczynski


Residential Peak Hour Usage Forecast
GTA Project Influence Area
1.58
1.56
1.54
1.52
1.5
1.48
1.46
1.44
1.42
10³m³/hr
y = -0.05ln(x) + 1.5607
Residential historical
peak hour usage data
2006-2007
2007-2008
2008-2009
2009-2010
2010-2011

UNDERTAKING JT2.28

UNDERTAKING

TR 2, page 154

To provide reduction in peak hourly loads by customer type that incorporates 35 percent reduction.

RESPONSE

As stated during the Technical Conference and in the response to Board Staff Interrogatory #15 found at Exhibit I.A3.STAFF.15, the Company has already responded to many interrogatories to provide peak load data by customer type. Such information was not tracked but derived using certain assumptions, any potential inconsistencies may not be easily traceable and interpretations should be weighed accordingly.

Please see the table on the following page for the reduction in peak daily loads by customer type for the forecast period. The “Net Load Forecast” row is the peak daily demand as listed in the response to Environmental Defence Interrogatory #3 found at Exhibit I.A4.EGD.ED.3 in Table 2 in the “Adds” row. The “Load Reduction” row is the derived reduction, by customer type or total, for the forecast period. The breakouts shown use the assumption that load reduction is directly proportional to load increase by sector.

Witness: C. Fernandes

PEAK LOAD (m3/day)		Growth Forecast												
		2012-2013	**2013-2014**	**2014-2015**	**2015-2016**	**2016-2017**	**2017-2018**	**2018-2019**	**2019-2020**	**2020-2021**	**2021-2022**	**2022-2023**	**2023-2024**	**2024-2025**
Apartment	Net Load Forecast	85236	72177	82516	84452	84135	80239	79246	79009	78095	77797	77797	77797	77797
	Load Reduction	45896	38865	44432	45474	45303	43205	42671	42543	42051	41891	41891	41891	41891
Commercial	Net Load Forecast	150221	143004	148131	158505	161725	151026	150999	150265	151214	151723	151723	151723	151723
	Load Reduction	80888	77002	79763	85349	87083	81322	81307	80912	81423	81697	81697	81697	81697
Industrial	Net Load Forecast	338	315	1991	2031	883	839	823	807	1073	1063	1063	1063	1063
	Load Reduction	182	170	1072	1093	475	452	443	434	578	572	572	572	572
Residential	Net Load Forecast	202193	212297	203708	213680	218824	225798	227037	229477	232336	235355	235355	235355	235355
	Load Reduction	108873	114314	109689	115058	117828	121583	122251	123565	125104	126730	126730	126730	126730
TOTAL	Net Load Forecast	437989	427794	436346	458668	465566	457901	458105	459559	462718	465938	465938	465938	465938
TOTAL	Load Reduction	235840	230350	234955	246975	250690	246562	246672	247455	249156	250889	250889	250889	250889

UNDERTAKING JT2.29

UNDERTAKING

TR 2, page 156

To advise how EGD's 0.65 reduction function was calculated with an explanation discussing all the factors it considers including DSM.

RESPONSE

There are a number of factors that influence peak load on the distribution system over time. Some factors, such as GDP growth or a trend to larger buildings which are taller and denser than historical multi-residential construction, would tend to push the peak load higher. Other factors, such as energy efficiency improvements to the existing building stock or installed base of equipment, or changes to Building Codes on new construction and renovations, would be expected to decrease peak load. The Company forecast includes all of the above items.

The Company did a comparison of the load growth forecast (aggregated by sector, by geography, over the project forecast horizon as explained in the response to Environmental Defence Interrogatory #12 found at Exhibit I.A4.EGD.ED.12) to the historical send-out trend on peak day normalized to design conditions. As a result the Company applied a reduction to the forecast of increased peak system loads. The reduction factor captures the impact of all of the factors listed above across the existing and incremental loads.

The table below shows the comparison of the previous period normalized peak day demand for the GTA Project Influence Area and the forecast without and with the reduction factor that was included in the project forecast.

Period	# of Years	Total Growth (GJ/d)	Total Growth (%)
1999-2012 [1]	13	406,923	19.5
2013-2025 forecast (No reduction factor)	13	334,736	13.9
2013-2025 forecast (with reduction factor)	13	217,578	9.0

1 - Normalized peak day demand regression on customer count

Witness: C. Fernandes

UNDERTAKING JT2.30

UNDERTAKING

TR 2, page 167

For ED IRR #42, provide further breakdown of what ‘other’ row in 2012 EGD commercial customer table represents.

RESPONSE

The response to Environmental Defence Interrogatory #42 found at Exhibit I.A4.EGD.ED.42 was completed on a best-effort basis using information available in the system. Sectorial breakdown was accomplished through the use of Standard Industry Classification (“SIC”) codes which is a non-mandatory field. For entries that did not have an SIC code indicated, it was included in the “Other” category. No further breakdown is available.

Witness: M.Suarez

UNDERTAKING JT2.31

UNDERTAKING

TR 2, page 169

To make best efforts to update reduction factor of 65 percent, assuming DSM doubles.

RESPONSE

The Company has made "best efforts" to perform the analysis. Under a hypothetical situation where the delivered results of the DSM programs were to double, the reduction factor consistent with the estimated peak load would be 0.31. In other words, instead of a reduction of 35%, there will be a reduction of 69%.

The same assumptions and caution apply as described in the response to Environmental Defence Interrogatory #14 found at Exhibit I.A4.EGD.ED.14. The Company does not believe this is achievable under the current DSM policy framework and system timing needs.

Witness: C. Fernandes

UNDERTAKING JT2.32

UNDERTAKING

TR 2, page 172

The portion of EGD's total residential, apartment, commercial and industrial sales in the GTA.

RESPONSE

Table 1 is the proportion of customer counts for the GTA Project Influence Area to the total franchise (based on 2012 data) by sector:

Table 1

2012 Customer Counts					
	Residential	Commercial	Apartment	Industrial	TOTAL
GTA Project Influence Area (derived)	893,936	79,543	4,701	4,816	982,996
Total Franchise	1,836,267	144,875	7,400	6,361	1,994,903
GTA Influence Area %	49%	55%	64%	76%	49%

The Company has not historically tracked customer information for sub-areas such as the GTA Project Influence Area. Instead, it relies on geographical areas denoted as Areas 10, 20, 30, 40, 50, 60, and 80 to track customer counts in different areas of the franchise within its Customer Information System ("CIS"). The GTA Project Influence Area resides in Areas 10, 20, and 30 and is a subset of these areas.

To derive customer numbers within the GTA Project Influence Area, it was necessary to map customers to the boundaries delineated by the influence area using postal Forward Sortation Areas ("FSAs") as tracked in the Pipeline Maintenance Tracking System ("PMTS"), which is the Company's asset information database. PMTS data were queried for total customers within the GTA Project Influence Area as well as for the total customers in Areas 10, 20, and 30 for each year of history provided. The ratio of customers in the GTA Project Influence Area relative to the combined Area 10, 20, and 30 as determined in PMTS was used to prorate the customer numbers as tracked in CIS to derive the historical customers within the GTA influence area for each year.

Witness: M. Suarez

Table 2 is the proportion of annualized volumes for the GTA Project Influence Area to the total franchise (based on 2012 data) by sector:

Table 2

2012 Annualized Volume (10^6m^3)					
	Residential	Commercial	Apartment	Industrial	TOTAL
Areas 10, 20, 30 (proxy for GTA Project Influence Area)	2,699	2,040	903	1,202	6,844
Total Franchise	4,225	3,118	1,048	2,108	10,499
GTA Influence Area %	64%	65%	86%	57%	65%

As described above, the Company has not historically tracked information for sub-areas such as the GTA Project Influence Area. To present historical information, the Company has used actual volumes from Franchise Areas 10, 20, and 30 from the billing system to proxy for volumes in the GTA Project Influence Area. The GTA Project Influence Area is a subset of Franchise Areas 10, 20 and 30.

As previously noted, Enbridge does not track the specific information that has been requested as the information is not required for system planning or rate-making purposes. As such, Enbridge has derived the data and provided the information to respond to the interrogatory and are for illustrative purposes only. Any potential inconsistencies may or may not be easily traceable. Interpretations or conclusions from the derived data should be weighed accordingly.

Witness: M. Suarez

UNDERTAKING JT2.33

UNDERTAKING

TR 2, page 173

To provide a table with the number of projects by year - industrial and total.

RESPONSE

The table below shows the number of projects by year – industrial and total as requested.

	Sum of Custom Projects				
Market	**2008**	**2009**	**2010**	**2011**	**2012**
Commercial	278	339	348	449	560
Multi-Res Non-Profit	20	11	53	146	57
Multi-Residential	235	257	275	320	275
Industrial	140	118	123	127	91
Total Custom Projects	**673**	**725**	**799**	**1,042**	**983**

Notes:
Custom projects may contain more than one measure.
2012 Multi-residential Non-profit projects were not delivered by EGD Sales.

Witnesses: T. MacLean
F. Oliver-Glasford
J. Ramsay

UNDERTAKING JT2.34

UNDERTAKING

TR 2, page 181

To fully describe the assumptions and methodology used by EGD to derive historical data in ED IR#4 and other interrogatories.

RESPONSE

The Company has not historically tracked customer information for sub-areas such as the GTA Project Influence Area. Instead, it relies on geographical areas denoted as Areas 10, 20, 30, 40, 50, 60, and 80 to track customer counts in different areas of the franchise within its Customer Information System ("CIS"). The GTA Project Influence Area resides in Areas 10, 20, and 30.

To derive customer numbers within the GTA Project Influence Area, it was necessary to map customers to the boundaries delineated by the Influence Area using each postal Forward Sortation Area ("FSA") as tracked in the Pipeline Maintenance Tracking System ("PMTS"), which is the Company's asset information database. PMTS data were queried for total customers within the GTA Project Influence Area as well as for the total customers in Areas 10, 20, and 30 for each year of history provided.

The ratio of customers in the GTA Project Influence Area relative to the combined Area 10, 20, and 30 as determined in PMTS was used to prorate the customer numbers as tracked in CIS to derive the historical customers within the GTA Project Influence Area for each year.

It should be noted that this and other specific information that have been requested are derived rather than tracked by Enbridge as the information is not required for system planning or rate-making purposes. Enbridge has derived the data and provided the information to respond to the interrogatories. Any potential inconsistencies may or may not be easily traceable. Interpretations or conclusions from the derived data should be weighed accordingly.

Witness: M. Suarez

UNDERTAKING JT2.35

UNDERTAKING

TR 2, page 184
Table with past 3 years of data expanding on ED IR #6 with Total Demand Data.

RESPONSE

The table on the following page shows the highest daily demands for the past three years.

Witness: J. Denomy

Gas Day	GTA Project Influence Area Flows (TJ)	Year
3-Jan-12	1,883.3	2012
14-Jan-12	1,807.9	2012
19-Jan-12	1,652.7	2012
15-Jan-12	1,641.8	2012
20-Jan-12	1,640.3	2012
11-Feb-12	1,626.5	2012
2-Jan-12	1,551.8	2012
18-Jan-12	1,538.1	2012
5-Mar-12	1,505.4	2012
13-Jan-12	1,490.4	2012
23-Jan-11	1,995.8	2011
31-Jan-11	1,857.2	2011
10-Feb-11	1,824.6	2011
8-Feb-11	1,822.8	2011
2-Feb-11	1,796.1	2011
1-Feb-11	1,764.1	2011
9-Feb-11	1,759.7	2011
24-Jan-11	1,757.1	2011
16-Jan-11	1,734.3	2011
12-Jan-11	1,716.2	2011
29-Jan-10	1,895.3	2010
13-Dec-10	1,860.2	2010
2-Jan-10	1,822.3	2010
3-Jan-10	1,802.5	2010
28-Jan-10	1,796.4	2010
14-Dec-10	1,750.6	2010
4-Jan-10	1,728.8	2010
8-Jan-10	1,700.5	2010
30-Jan-10	1,679.6	2010
9-Jan-10	1,669.9	2010

UNDERTAKING JT2.36

UNDERTAKING

TR 2, page 187

To respond to ED letter from #12 onwards or explain why it cannot be provided or explain where it has already been provided.

RESPONSE

The following are responses from the Environmental Defence letter dated June 11, 2013 from #12 onwards. Responses to the first 7 questions (#3, 4, 5, 6, 7, 8, and 9) were provided at the Technical Conference. Written responses to #4 and 8 have also been included below.

Interrogatory No. I.A4.EGD.ED.4

In the letter from Environmental Defence, dated June 11, 2013:

> *This interrogatory requested "for each year from 2000 to 2025 inclusive Enbridge's actual/forecast total number of residential, commercial, apartment and industrial customers in the GTA Project Influence Area."*
>
> *(i)* *No data was provided for 2022 to 2025 and no explanation was provided for this missing data. We request this data be provided.*
>
> *(ii)* *The response states that "[t]o present historical information for the GTA project Influence Area, customer numbers have been derived based on one or more data systems…" Please provide fully describe the assumption and methodology used by Enbridge to derive this historical data in this and other interrogatory responses.*

Enbridge provides the following response:

(i) The forecast of customer growth was originally carried out for the period from 2013 to 2021. To extend the forecast to 2025 for purposes of the GTA Application, the Company used the same level of growth as in 2021 for each of the years to 2025 based on number of customers.

Witnesses: C. Fernandes
T. MacLean
E. Naczynski
F. Oliver-Glasford
J. Ramsay
M. Suarez

The table of Total Customers by Sector, originally provided in I.A4.EGD.ED.4, failed to extend the forecast period beyond 2021 and it was not acknowledged in the explanation. That table is here updated to provide the full forecast from 2013 to 2025.

Total Customers by Sector				
	Apartment	Commercial	Industrial	Residential
2004	4,424	68,606	4,773	777,117
2005	4,471	69,885	4,792	796,860
2006	4,497	71,388	4,798	816,062
2007	4,540	73,351	4,805	832,492
2008	4,543	74,848	4,807	849,520
2009	4,564	76,250	4,807	863,284
2010	4,600	77,449	4,812	873,205
2011	4,675	78,626	4,812	884,673
2012	4,701	79,543	4,816	893,936
2013	4,729	80,563	4,823	904,728
2014	4,803	81,718	4,824	916,831
2015	4,872	82,918	4,827	928,500
2016	4,943	84,208	4,830	940,776
2017	5,014	85,535	4,833	953,383
2018	5,083	86,785	4,835	966,418
2019	5,152	88,037	4,837	979,565
2020	5,220	89,288	4,839	992,896
2021	5,287	90,549	4,841	1,006,431
2022	5,354	91,819	4,843	1,020,180
2023	5,421	93,088	4,845	1,033,928
2024	5,488	94,357	4,847	1,047,676
2025	5,555	95,626	4,849	1,061,424

The forecast is layered on the derived actuals, as further explained in part (ii) on the next page, and is denoted by the shaded area.

(ii) The Company has not historically tracked customer information for sub-areas such as the GTA Project Influence Area. Instead, it relies on geographical areas denoted as Areas 10, 20, 30, 40, 50, 60, and 80 to track customer counts in different areas of the franchise within its Customer Information System ("CIS"). The GTA Project Influence Area resides in Areas 10, 20, and 30.

Witnesses: C. Fernandes
T. MacLean
E. Naczynski
F. Oliver-Glasford
J. Ramsay
M. Suarez

To derive customer numbers within the GTA Project Influence Area, it was necessary to map customers to the boundaries delineated by the influence area using postal Forward Sortation Areas ("FSAs") as tracked in the Pipeline Maintenance Tracking System ("PMTS"), which is the Company's asset information database. PMTS data were queried for total customers within the GTA Project Influence Area as well as for the total customers in Areas 10, 20, and 30 for each year of history provided.

The ratio of customers in the GTA Project Influence Area relative to the combined Area 10, 20, and 30 as determined in PMTS was used to prorate the customer numbers as tracked in CIS to derive the historical customers within the GTA influence area for each year.

Interrogatory No. I.A4.EGD.ED.8

In the letter from Environmental Defence, dated June 11, 2013:

> *This interrogatory requested "for each year from 2000 to 2025 inclusive the actual/forecast total demands (TJ/year) and average annual demands (GJ/year)" for certain customer classes.*
>
> *Enbridge did not provide the total or average demands as requested. Instead, it referred to a portion of the evidence containing the incremental demands of new customers, which is not the information requested in this interrogatory.*
>
> *Enbridge also stated that "[p]ipeline and facilities requirements are based on total peak hourly demand." However, that does not mean that the requested data is irrelevant. The annual demands are relevant to DSM as a possible alternative. For example, DSM programs are often described in terms of annual demands. Furthermore, annual demands could be a factor in determining the economic cost/benefit analysis of DSM as an alternative.*
>
> *We therefore ask that a complete response (existing and incremental) be provided.*

Enbridge provides the following response:

As indicated in the response to Board Staff Interrogatory #15 found at Exhibit I.A3.EGD.STAFF.15, the Company has not historically tracked information for sub-areas such as the GTA Project Influence Area. To present historical information, Enbridge has used actual volumes from Franchise Areas 10, 20, and 30 from the billing system to proxy for volumes in the GTA Project Influence Area. Average use forecasts by sector using 2013 Board-approved average use were applied to GTA Project Influence area customer growth forecasts to project total annual demands.

Witnesses: C. Fernandes
T. MacLean
E. Naczynski
F. Oliver-Glasford
J. Ramsay
M. Suarez

As previously noted, Enbridge does not track the specific information that has been requested as the information is not required for system planning or rate-making purposes. As such, Enbridge has derived the data and provided the information to respond to the interrogatory and are for illustrative purposes only. Any potential inconsistencies may or may not be easily traceable. Interpretations or conclusions from the derived data should be weighed accordingly.

With respect to the forecast average usage beyond 2013, data is not available.

Total Illustrative Annual Demand and Average Use
GTA Project Influence Area, by Sector, 2000-2025

	Residential		Commercial		Apartment		Industrial		Total
	Volumes (10^6m^3)	Rate 1 Average Use (m^3)	Volumes (10^6m^3)	Rate 6 Average Use (m^3)	Volumes (10^6m^3)	Rate 6 Average Use (m^3)	Volumes (10^6m^3)	Rate 6 Average Use (m^3)	Volumes (10^6m^3)
2000	2,723	3,092	2,353	18,000	1,024	82,043	1,661	59,697	7,761
2001	2,638	2,960	2,278	17,750	992	82,147	1,562	55,885	7,470
2002	2,799	2,953	2,372	17,744	1,028	83,354	1,597	54,315	7,795
2003	3,068	2,938	2,522	17,738	1,092	84,736	1,597	57,283	8,279
2004	2,928	2,889	2,404	17,611	1,032	84,719	1,579	52,838	7,944
2005	3,043	2,815	2,465	17,200	1,034	81,085	1,581	53,657	8,124
2006	2,813	2,776	2,318	17,362	988	88,822	1,509	56,659	7,628
2007	3,042	2,769	2,436	17,831	1,014	103,512	1,515	61,632	8,007
2008	3,066	2,737	2,363	18,614	1,017	128,289	1,447	76,114	7,893
2009	3,066	2,694	2,234	19,133	965	145,642	1,234	89,273	7,498
2010	2,859	2,657	2,122	19,818	979	164,942	1,264	108,449	7,224
2011	3,041	2,618	2,295	20,261	1,004	154,154	1,278	109,505	7,619
2012	2,699	2,601	2,040	20,240	903	151,332	1,202	107,958	6,844
2013	2,730	2,568	2,063	20,230	914	154,877	1,202	109,481	6,910
2014	2,760		2,087		925		1,203		6,975
2015	2,776		2,100		931		1,203		7,010
2016	2,808		2,127		942		1,203		7,080
2017	2,841		2,153		952		1,203		7,150
2018	2,875		2,178		963		1,204		7,219
2019	2,909		2,203		974		1,204		7,290
2020	2,943		2,229		984		1,204		7,360
2021	2,978		2,254		995		1,204		7,431
2022	3,013		2,280		1,005		1,204		7,503
2023	3,049		2,306		1,015		1,205		7,575
2024	3,084		2,331		1,026		1,205		7,646
2025	3,102		2,344		1,031		1,205		7,682

Volumes: Actual volumes from 2000 - 2012 represent Franchise Areas 10, 20, 30.
Forecast volumes for 2013 and 2014 taken by applying 2013 average annual volume per customer on customer growth forecasts for 2013 & 2014 for the GTA Project Influence Area as shown in I.A4.EGD.ED.2. Average Annual volume as shown at Ex E Tab 1 Schedule 1 page 8.
Forecast volumes for 2015-2025 for the GTA Project Influence Area incrementally added from Ex E T1 S1 p.8.

Average Use: Actual average use volumes normalized to 2013 Board-Approved degree days by General Service sector.
Forecast average use currenly available for 2013 Test year only.

All forecasts denoted in shaded areas.

Witnesses: C. Fernandes
T. MacLean
E. Naczynski
F. Oliver-Glasford
J. Ramsay
M. Suarez

Interrogatory No. I.A4.EGD.ED.12

In the letter from Environmental Defence, dated June 11, 2013:

> *This interrogatory requested that Enbridge "fully describe the methodology and assumptions for Enbridge's annual residential, commercial, apartment and industrial customer load growth forecasts from 2013 to 2025 inclusive in the GTA Project Influence Area. . ."*
>
> > *(i) Enbridge did not explain the methodology and assumptions used to derive its incremental customer forecast, and we therefore ask that this be provided.*
> >
> > *(ii) Enbridge's response states that an "additional reduction factor" was applied for that GTA Project and that this additional factor is explained in the response to Environmental Defence Interrogatory No. 13 (c). However, that reduction factor is not in fact explained therein. We ask that an explanation be provided*.

Enbridge provides the following response:

(i) Please see the Company's response to GEC Interrogatory #13 found at Exhibit I.A1.EGD.GEC.13. The starting point of the customer additions forecast is the long-range forecast for customer growth as developed as part of Enbridge's Long Range Plan process. To derive customer growth within the GTA Project Influence Area for the purpose of load simulation, it was necessary to map customers to the boundaries delineated by the Influence Area using each postal Forward Sortation Area ("FSA") as tracked in the Pipeline Maintenance Tracking System ("PMTS"), which is the Company's asset information database. PMTS data were queried for total customers within the GTA Project Influence Area as well as for the total customers in Areas 10, 20, and 30 for each year of history provided. Through regression analysis, correlations with PMTS data were used to translate the LRP customer additions forecasts for Areas 10, 20, and 30 to GTA Project Influence Area equivalents.

(ii) Please refer to the response to Undertaking JT2.29.

Interrogatory No. I.A4.EGD.ED.13

In the letter from Environmental Defence, dated June 11, 2013:

Witnesses: C. Fernandes
T. MacLean
E. Naczynski
F. Oliver-Glasford
J. Ramsay
M. Suarez

This interrogatory is related to Enbridge's growth forecast and the reduction factor applied to account for DSM and customer losses.

(i) What are the units for the data in Table 1? Are they per customer averages?

(ii) In the response to part (a) of this interrogatory, Enbridge did not include the loads of its unbundled customers in the data and did not explain why that information was omitted. Please provide a revised interrogatory response including a best estimate of the unbundled customers, stating assumptions if necessary. Alternatively, please explain why this information cannot be provided.

(iii) With respect to part (c) of this interrogatory, please provide a break out of the reduction factor according to efficiency gains and customer losses as requested.

(iv) Part (c) of this interrogatory asks that Enbridge fully explain how its DSM reduction factor is calculated. Enbridge's response states that "The reduction factor was developed using gate station daily demand trends in the GTA. Please provide the time period of the trend analysis and explain how the trend was calculated.

(v) With respect to part (c) of this interrogatory, Enbridge simply states that the reduction factor is 0.65. Please explain what units the 0.65 reduction factor is in and explain how the factor is applied.

(vi) With respect to part (c) of this interrogatory, please explain whether the reduction factor was applied to existing loads.

(vii) Please provide a response to part (d) of this interrogatory.

Enbridge provides the following response:

(i) Please see the June 13, 2013 Technical Conference transcript starting on page 161 at line 27 and ending on page 162 at line 9. The data includes customer averages for peak hourly load in cubic meters per hour.

(ii) Please see the June 13, 2013 Technical Conference transcript starting on page 179 at line 19 and ending on page 180 at line 6.

(iii) The reduction factor was not a bottom up detailed aggregation of individual items. Please refer to the response to Undertaking JT2.29. The factor was a top down estimate of the total impact of all factors impacting peak demand on the system.

Witnesses: C. Fernandes
T. MacLean
E. Naczynski
F. Oliver-Glasford
J. Ramsay
M. Suarez

(iv) Please refer to the response to Undertaking JT2.29.

(v) The reduction factor has no units as it is a multiplier. Please see the June 13, 2013 Technical Conference transcript starting on page 152 at line 23 and ending on page 152 at line 26.

(vi) Please refer to the response to Undertaking JT2.29.

(vii) Please refer to the response to Undertaking JT2.29.

<u>Interrogatory No. I.A4.EGD.ED.14</u>

In the letter from Environmental Defence, dated June 11, 2013:

> *(i) Part (a) of this interrogatory requested the forecast impact of DSM as calculated using the "reduction factor" for each year from 2014 to 2025. However, the response provided just one number, 13,000 cubic metres per hour. Please provide the values for each year or an explanation of why the result is constant over time.*
>
> *(ii) Part (b) of this interrogatory asked that Enbridge "state the amount of DSM, in addition to that assumed in Enbridge's forecast, that would be needed to meet Enbridge's customers' needs in the GTA Project Influence Area in each year from 2014 to 2025 inclusive." Enbridge's response provided annual data, but not hourly data, even though required pipeline facilities are a function of peak hourly demand. Please provide the amount of DSM in cubic metres per hour on peak that is needed to avoid the pipeline in each year from 2014 to 2025 inclusive.*
>
> *(iii) According to Enbridge's response, additional annual DSM savings of 77,811,000 cubic metres per year would be needed in the GTA to meet growth needs without the pipeline. According to Enbridge this would entail an annual increase of the DSM budget of approximately $33.8 million.*
>
> *Environment Defence requested Enbridge's "analyses" to support its incremental DSM estimates. However. Enbridge has not provided us with its inputs or calculations to support the above estimates. Please provide these inputs and calculations so we can understand how $33.8 million cost was calculated. Please also provide Enbridge's estimate of the net TRC benefits of these incremental DSM programs (see also ED IR No. 40).*

Enbridge provides the following response:

(i) Please see the June 13, 2013 Technical Conference transcript starting on page 162 at line 10 and ending on page 164 at line 6.

Witnesses: C. Fernandes
T. MacLean
E. Naczynski
F. Oliver-Glasford
J. Ramsay
M. Suarez

(ii) ED's Interrogatory #14 did not request that the amount of DSM necessary to offset GTA load growth be expressed as peak hour demand reduction. DSM results are forecast and reported in annual savings. For the purposes of this response, the Company has converted the annual results to peak hour demand reduction. Please see below the amount of DSM necessary to offset GTA load growth expressed as peak hour demand reduction. Please note that this increase in DSM would account only for the load growth portion of the GTA Project and does not address any other component of the Project.

DSM Required to Offset Growth in the GTA Project Influence Area	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Additional Peak Hour DSM Needed in GTA (10^3m^3)	25	25	25	25	25	25	25	25	25	25	25	25

(iii) Please see Enbridge's response to Undertaking JT2.20 for a more detailed description of the Company's calculations in generating illustrative figures for the additional DSM results necessary to offset load growth in the GTA as well as the TRC benefits associated with this increase.

In regards to ED's request for the Company's methodology for calculating the corresponding budget increase, Enbridge divided current forecast annual DSM results by the total franchise-wide DSM results necessary to offset GTA growth (a figure derived for illustrative purposes, and which has a large degree of uncertainty) to create a factor representing the increase in DSM results that would be necessary to offset GTA load growth annually (313%). The portion of the current budget proposed for 2014 in the GTA area (48% of the entire 2014 budget) was then multiplied by the above noted factor, resulting in a GTA specific budget of approximately $50M, and a franchise-wide DSM budget of approximately $67 million annually. For greater clarity, the total GTA Project Influence Area DSM spending to offset the GTA load growth (but not address any of the Project's other drivers) would be approximately $50 million, roughly three times the currently projected DSM spending for the GTA area per year. If the required DSM budget to offset the load growth portion of the project only were projected out over the forecast of the initiative (i.e., ten years of growth offset), required DSM spending in the GTA would be over $500 million.

Interrogatory No. I.A4.EGD.ED.17

In the letter from Environmental Defence, dated June 11, 2013:

> *According to the response to ED IR No. 17, the GTA system has a peak hour capacity of 3,037,000 cubic metres. According to the response to ED IR No. 3, the peak hour demand in 2015/16 will be 2,978,023 cubic metres. Thus, according to those figures, there will be a capacity surplus of 58, 977 cubic metres in 20 15/16. This is equivalent to a surplus of 2.2 TJ since there are 37.69 MJ/cubic metres (ED IR No. 3).*
>
> *However, according to response to ED IR No. 25, in 2015/16, there is capacity deficit of 15,000 cubic metres per hour.*
>
> *Please explain the error or discrepancy.*

Enbridge provides the following response:

Please see the June 13, 2013 Technical Conference transcript starting on page 164 at line 7 and ending on page 165 at line 4.

Interrogatory No. I.A4.EGD.ED.19

In the letter from Environmental Defence, dated June 11, 2013:

> *This interrogatory asks:*
>
> > *When did Enbridge start to analyse the potential for incremental DSM programs and budgets to defer the need for some or all of the proposed GTA Pipeline Project? Please provide copies of the written materials prepared by Enbridge in this regard corresponding to this start date.*
>
> *The response does not provide (i) the date when DSM was first considered and screened out as an alternative, (ii) the analyses used to screen out DSM, or (iii) the written materials prepared by Enbridge in this regard. Enbridge did not explain why that requested information was omitted, and we therefore ask that it be provided.*

Enbridge provides the following response:

Please see the June 13, 2013 Technical Conference transcript starting on page 165 at line 5 and ending on page 166 at line 24.

Witnesses: C. Fernandes
T. MacLean
E. Naczynski
F. Oliver-Glasford
J. Ramsay
M. Suarez

Interrogatory No. I.A4.EGD.ED.24

In the letter from Environmental Defence, dated June 11, 2013:

> *Part (c) of this interrogatory asks:*
>
> > *Assuming that the load growth to be addressed by the proposed facilities were to be instead addressed by targeted DSM (and assuming that this is possible),could that DSM be implemented in any of the 152 smaller geographic areas inside the larger GTA Project Influence Area? For example, would targeted DSM need to be predominantly located in an area nearby to station B or in areas served by proposed segment B?*
>
> *Enbridge did not respond to part (c) or (d) of this interrogatory and instead simply stated that "Enbridge does not believe that targeted DSM can eliminate the need for some or all of the proposed facilities." However, Environmental Defence was not asking whether targeted DSM can eliminate the need for the project. Instead, we were asking, in essence, where targeted DSM would need to be located if it were the case that DSM could sufficiently address load growth issues. We ask that a full response be provided to parts (c) and (d) of this interrogatory.*

Enbridge provides the following response:

Please see the June 13, 2013 Technical Conference transcript starting on page 174 at line 23 and ending on page 178 at line 24.

Interrogatory No. I.A4.EGD.ED.25

In the letter from Environmental Defence, dated June 11, 2013:

> *Please provide the annual demand forecast from 2013 to 2025 as requested. No explanation has been provided for what this information was omitted.*

Enbridge provides the following response:

The Company did provide the requested data in Exhibit I.A4.EGD.ED.25 including reference to Exhibit I.A4.EGD.ED.3

Interrogatory No. I.A4.EGD.ED.26

In the letter from Environmental Defence, dated June 11, 2013:

> *Please provide a response to part (e) of this interrogatory, which requested "Enbridge's forecast of its Ontario customers' peak hour, peak day and annual demands for natural gas (net of DSM) for each year from 2013 to 2025 inclusive." Enbridge has stated that this information is not*

Witnesses: C. Fernandes
T. MacLean
E. Naczynski
F. Oliver-Glasford
J. Ramsay
M. Suarez

> *available, but there is no apparent reason why it cannot be created. Environmental Defence wishes to know the annual demands of all of Enbridge's Ontario customers to evaluate whether this proposal (which is predicated on steadily increasing gas usage in the GTA) is consistent with Ontario's greenhouse gas emission reduction targets.*

Enbridge provides the following response:

As indicated in the original interrogatory response, the application deals with facilities in the GTA only. Enbridge has not compiled information for its entire franchise in a comparable fashion and this information is not available.

Interrogatory No. I.A4.EGD.ED.39

In the letter from Environmental Defence, dated June 11, 2013:

> *Parts (a)(ii) and (iii) of this interrogatory requested the following:*
>
> > *Please provide a table indicating the following estimates for each year from 2014 to 2025 for the GTA Project Influence Area:*
> >
> > > *ii. The estimated reduction in peak hourly consumption (GJ/hour) resulting from the implementation of all industrial DSM programs with a TRC benefit cost ratio of 1 or greater; and*
> > > *iii. The estimated yearly resource acquisition industrial DSM budget needed to implement all industrial DSM programs with a TRC benefit cost ratio of1 or greater.*
>
> *Enbridge responded as follows: "The data required to provide this analysis is not available to Enbridge. A 2008 DSM Potential Study filed as EB-201 1-0295 Ex.B, Tab 2, Sch. 7, estimated the potential results from implementation of all industrial DSM programs with a TRC benefit-cost ratio of I or greater across the franchise area. While the GTA Project Area represents approximately 48% of the customers across the franchise area, it does not represent 48% of the industrial customers. As a result, the Company cannot extrapolate the Potential Study results to the GTA Area." It is not apparent why an estimate of the cost-effective industrial DSM potential cannot be produced as long as certain assumptions are made, such as assumptions relating to the proportion of Enbridge's industrial customers that are located in the GTA Area. We ask that Enbridge estimate the cost-effective industrial DSM potential (as requested in the interrogatory) based on a reasonable set of assumptions. As indicated in the interrogatory, we ask that you "show your analysis and state all assumptions."*

Enbridge provides the following response:

As stated in the interrogatory response, "The data required to provide this analysis is not available to Enbridge." The amount of assumptions required to determine all cost effective DSM looking forward would be substantial as would the uncertainty in the assumptions. The 2008 DSM Potential Study, a comprehensive study building some

Witnesses: C. Fernandes
T. MacLean
E. Naczynski
F. Oliver-Glasford
J. Ramsay
M. Suarez

basis on which to make estimates on cost effective, and achievable results from the market, estimated annual results across the franchise area. The annual gas savings in 2017 from implementation of all Achievable measures in the industrial sector with a TRC cost benefit ratio of one or greater was estimated by the DSM Potential Study as $48Mm^3$. The associated annual budget in the industrial sector was estimated as $4.4M.

Interrogatory No. I.A4.EGD.ED.40

In the letter from Environmental Defence, dated June 11, 2013:

> *This interrogatory requested "Enbridge's best estimates of the economic benefits in each year from 2013 to 2025 inclusive of DSM measures that would be sufficient to avoid the need for increased pipeline capacity to meet the forecast rising demand for natural gas in the GTA Project Influence Area."*
>
> *Enbridge did not calculate all of the gas supply savings on the grounds that "Enbridge does not believe that increased DSM can realistically be expected to offset the forecast load growth." However, this is not a valid reason to not provide an interrogatory response. Environmental Defence requests that a full and adequate response be provided.*
>
> *Environmental Defence requires this key information to calculate the net benefits of DSM programs. That is, the net benefit of DSM programs is the avoided gas supply costs minus the incremental costs of the DSM measures*

Enbridge provides the following response:

As stated in the technical conference, the need for increased pipeline capacity is based on a number of requirements, including forecast load growth. If forecast load growth was eliminated, the pipeline facilities would still be required in order to meet the other requirements.

Please see the response to Undertaking JT2.20 for the incremental net TRC benefits and total franchise-wide TRC benefits that would result from the illustrative increase in DSM within the GTA Project Influence Area that would be necessary to offset load growth.

Interrogatory No. I.A4.EGD.ED.42

In the letter from Environmental Defence, dated June 11, 2013:

> *This interrogatory requested that Enbridge:*

Witnesses: C. Fernandes
T. MacLean
E. Naczynski
F. Oliver-Glasford
J. Ramsay
M. Suarez

Please state the current total number of Enbridge's commercial customers. Please also provide a breakdown of those customers by type (such as schools, hotels, office buildings, etc.). Please provide all breakdowns of commercial customers by type that are available.

Enbridge's response included a category entitled "other" that accounts for almost 2/3 of the customers and half of the volume. Please provide a further breakdown of the "other" category and explain what it contains.

Enbridge provides the following response:

Please see the response to Undertaking JT2.30.

Witnesses: C. Fernandes
T. MacLean
E. Naczynski
F. Oliver-Glasford
J. Ramsay
M. Suarez

UNDERTAKING JT2.37

UNDERTAKING

TR 2, page 189 and onto 190

To provide Enbridge's capacity on that line and whether or not that capacity included growth.

RESPONSE

The Company understood the question as follows:

1. Have we contracted for the 800, 000 GJ/d on TCPL from Parkway to Bram West?
2. Does the 800, 000 GJ/d include franchise growth?
3. Has the Board approved that contract or is it part of the approvals that is being requested in this application?

The responses are as follows:

1. No. Enbridge has not contracted for the 800,000 GJ/d on TCPL from Parkway to Bram West.

   The MOU with TransCanada contemplates two firm transportation contracts with TransCanada: 200,000 GJ/d from Niagara Falls to Parkway Enbridge CDA and 800,000 GJ/d from Parkway to Bram West.

   As discussed by Ms. Giridhar at June 12, Technical Conference Transcript, page 95, lines 18 to 20, the 200,000 GJ/d firm transportation contract from Niagara Falls to Enbridge Parkway CDA is embodied in the MOU with TransCanada as an intent at this point in time. Likewise the 800,000 GJ/d firm transportation contract from Parkway to Bram West is embodied in the MOU with TransCanada as an intent at this point in time. Under the MOU with TransCanada Enbridge has an obligation to bid for both contracts.

2. The 800,000 GJ/d from Parkway to Bram West is expected to be fully utilized under peak day or design conditions from the 2015 in service date onwards. Enbridge will contract for additional amounts of short haul capacity and supply over the 2015 to 2025 period to accommodate growth. Please see the response to BOMA Interrogatory #18 found at Exhibit I.A1.A3.EGD.BOMA.18 for a discussion of how Enbridge expects to utilize the Bram West interconnect, the

Witness: C. Fernandes

contracts contemplated in the MOU with TransCanada, and the incremental M12 transportation capacity with Union Gas.

3. The Board has not approved either the Niagara Falls to Parkway Enbridge CDA contract or the Parkway to Bram West contract. Enbridge is not seeking Board approval of these contracts in this LTC application, however Enbridge's ability to enter into the contracts requires the GTA Project to be approved and in service.

UNDERTAKING JT2.38

UNDERTAKING

TR 2, page 191

To provide a complete response to CCC#20 to discuss effects of using 1997–2012 as opposed to 2004-2012.

RESPONSE

The data in Figures 2 to 5 in Exhibit A, Tab 3, Schedule 5 were provided in the context of how the distribution system load factor has evolved over time and to explain the subsequent impacts on upstream contracting practices and upstream capacity utilization. The Company expects that it will continue to add temperature sensitive loads and that as a result it will be more efficient to contract for increasing amounts of short haul capacity to meet this demand.

The 2004 to 2012 trend lines produced in response to CCC #20 show a different trend relative to the trend lines provided in Exhibit A, Tab 3, Schedule 5, Figures 2 to 5. As indicated in the response to CCC Interrogatory #20 (b) found at Exhibit I.A4.EGD.CCC.20 longer term trends remove the noise associated with utilizing a shorter sample period. The Company believes that the longer term trend, the trend from 1997 or 1999 to 2012 is more representative of the trend that can be expected in the future rather than the shorter term trend from 2004 to 2012. The longer term trend better represents future trends in that it covers more economic cycles and a period over which the Company has experienced significant growth in the number of temperature sensitive customers. The Company expects to continue to add temperature sensitive loads and consequently expects the trend to a peakier load profile to continue.

While representative of what has occurred in the past and what can be expected in the future in terms of the distribution system load factor, Figures 2 to 5 in Exhibit A, Tab 3, Schedule 5 do not explicitly take into account certain other factors that could impact the trend lines presented. For example, the data in these figures have not been adjusted to include differences between contract demand and actual usage for contract customers and future efficiency gains. Each of these factors has been taken into account in the network modeling for the GTA Project. Consequently, the trend lines presented in Exhibit A, Tab 3, Schedule 5, Figures 2 to 5 are not directly comparable to the projected peak day demands provided in Exhibit A, Tab 3, Schedule 4, Table 3.

Witness: J. Denomy