PROVINCE OF ONTARIO

BEFORE THE ENERGY BOARD

Enbridge Gas Distribution Inc.	**)**	EB-2012-0451/0433/0074
GTA Project	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE GREEN ENERGY COALITION

Resource Insight, Inc.

JUNE 28, 2013

Confidential information has been redacted from this version.

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ADDITIONAL EXHIBIT

I. Identification & Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking (PBR) and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in **Error! Reference source not found.**.

Q: Have you previously presented evidence before the Ontario Energy Board?

A: Yes. I filed evidence and/or testified before the Ontario Environmental Assessment Board in Ontario Hydro's Demand/Supply Plan hearings in 1992, and before the OEB in the following dockets:

- EBRO 490, DSM cost recovery and lost-revenue adjustment mechanism for Consumers Gas.
- EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas.
- RP-1999-0034, performance-based rates for electric distribution utilities.
- RP-1999-0044, Ontario Hydro transmission-cost allocation and rate design.
- RP-1999-0017, Union Gas proposal for performance-based rates.
- RP-2002-0120, Ontario transmission-system code.
- RP-2004-0188, cost recovery and DSM for electric-distribution utilities
- EB-2005-0520, rate design and cost allocation for Union Gas firm customers.
- EB-2006-0021, gas utility DSM planning and cost recovery.
- EB-2007-0707, review of Ontario Power Authority's Integrated Power System Plan.
- EB-2007-0905, Ontario Power Generation (OPG) prescribed-facilities rate for 2009–2010.
- EB-2010-0008, OPG prescribed-facilities rate for 2011–2012.

In addition, I have assisted my clients in preparation of comments in various proceedings, including the distributed generation consultation (EB-2007-0630), the electric distribution rate design proceeding (EB-2007-0031) the distribution-utility decoupling case (EB-2010-0060), and incentive rate making for OPG's prescribed generation assets (EB-2012-0340).

Q: Have you testified previously in utility proceedings in other jurisdictions?

A: Yes. I have testified over two hundred and fifty times on utility issues before various regulatory, legislative, and judicial bodies, including

- one proceeding in Alberta,
- one proceeding in British Columbia
- four proceedings in Manitoba,
- thirteen proceedings in Nova Scotia,
- utility regulators in over thirty states, and
- two U.S. Federal agencies (NRC and FERC).

These testimonies are listed in my qualifications.

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Green Energy Coalition.

Q: What is the purpose of your testimony?

A: My clients have asked me to review a set of issues related to the request by Enbridge Gas Distribution (Enbridge or the Company) for leave to construct approximately $623.7 million in pipelines and related facilities in the Greater Toronto Area (GTA), particularly with regard to the extent that expanded demand-side management (DSM) could defer or avoid some or all of the capital investments.

My testimony focuses primarily on the following topics:

- The Company's planning process for these facilities,
- identification of the facilities that could be avoided through load-reductions,
- estimation of the annual costs of the facilities potentially avoidable by load reductions,
- the potential magnitude of required load reductions, and
- options for reducing load in the relevant area.

Q: Please describe the Company's proposed GTA Project.

A: Enbridge is requesting approval of the following four major components:

- A new gate station at the proposed Union Gas Parkway West compressor station, and a connection to the Company's Parkway North pipeline.
- A new major pipeline (Segment A), from a new TransCanada Pipelines (TCPL) gate station in Brampton, east to Albion Road, along the western half of the Company's existing NPS 36 Parkway North pipeline.[1]
- A second new pipeline (Segment B1), paralleling the eastern quarter of the Parkway line, to a new station at Buttonville on the Company's Don Valley Line, which runs south from the TCPL mainline at Victoria Square to Station B at the eastern edge of downtown Toronto.[2]

[1] Enbridge has given TCPL an option to use a portion of the capacity on this pipeline. The size of this line and access of other parties to the line are in dispute in this proceeding.

[2] The designations of Station B and Segment B appear to be coincidental.

- A third pipeline (Segment B2), continuing south from Buttonville along a portion of the Don Valley pipeline.

In dockets that are being heard with the Enbridge proposals, Union Gas has proposed facilities that, among other things, would increase capacity from Dawn to Parkway and would be necessary to fully serve the Company's GTA Project. As I explain below, my testimony does not address the Union Gas facilities.

Q: What materials did you review in preparing this evidence?

A: Along with Jonathon Wallach, vice president at Resource Insight, and with John Rosenkranz of North Side Energy, LLC, I have reviewed the Company's Application in this proceeding, its responses to discovery by GEC and other parties, the transcript of the technical conference on June 12 and 13, and the Company's responses to undertakings from the technical conference. We also reviewed other information on the configuration and constraints on the relevant portions of the gas transmission system and related issues. Mr. Rosenkranz has appeared before the OEB in the Natural Gas Electricity Interface Review proceeding (EB-2005-0551), the 2010 Natural Gas Market Review (EB-2010-0199), and the Union Gas 2013 Rate Case (EB-2011-0210). He has been a consultant to the Ontario Power Authority since 2006, assisting the Authority in evaluating natural gas supply, transportation and storage services for power generating plants supplied by Union and Enbridge.

Q: What justifications has Enbridge advanced for the various portions of its GTA Project?

A: While the Company's justifications for the various portions of the GTA Project have not always been clear, my understanding is that the Company's position comprises the following seven arguments:

1. The Parkway West gate station is needed for redundancy, since Enbridge receives a majority of the GTA's gas through the existing Parkway station.
2. The Parkway West gate station, Segment A and Segment B1 are necessary to bring lower-priced gas from the U.S., to replace gas shipped from western Canada at the higher-cost TCPL mainline tariffs.
3. Enbridge has also suggested that its interest in increasing its take from Union's facilities to the west is motivated in part by TransCanada's proposals to change the renewal provisions for firm transportation contracts (Exhibit A.3.1 p. 8; Tr. April 30 2013 p. 72).
4. Capacity on TransCanada's mainline may be reduced, since TCPL has indicated that it will be requesting permission from the National Energy Board to convert a portion of its gas pipeline capacity to carry tar-sands oil east.
5. Changes in TransCanada rate design also makes winter-only purchases of short-term firm transportation capacity on the TCPL mainline less certain and more expensive.
6. Pipeline Segments A, B1 and B2 would allow Enbridge to reduce the required operating pressure on NPS 26 pipeline from Keele/CNR to the Don Valley Line, as well as on the NPS 30 Don Valley pipeline.
7. Pipeline Segment B2 would be needed to provide adequate pressure at Station B at the end of the Don Valley line under design peak conditions.

As I discuss below, I have not taken any position on the merits of Justification 1, or of Justifications 2–5 for Parkway West and Segment A. Enbridge has not demonstrated that Justifications 2–5 actually support the economics of Segment B1. While lowering the operating pressure on an older pipeline may be desirable, Enbridge has not provided any substantial support for

Justification 6 let alone enough to justify spending hundreds of millions of dollars to alleviate pressure on the Don Valley line, especially since load reductions may also reduce required pressure. Finally, Justification 7 must be rejected since Enbridge has not examined the potential for less-expensive means of maintaining adequate pressure at Station B under design peak conditions.

Q: Which of these facilities and justifications will you address?

A: Based upon my review of the record in this case, and consultation with the GEC's consultant John Rosenkranz, I do not believe that the Parkway West gate station and Segment A can be avoided by plausible load reductions.[3] If Parkway West is justified for redundancy in supply at current loads, it would probably also be justified at significantly lower load levels. Similarly, the economics of accessing additional supplies of U.S. gas are not likely to be changed very much by plausible load reductions. Hence, I do not discuss those parts of the GTA Project.

Similarly, Union Gas has asserted that its proposed facilities are justified by providing additional U.S. gas to Enbridge, Union's own customers, and purchasers in Quebec, New York, and New England. Load reductions in Enbridge and Union Gas service territories in Ontario do not seem likely to change the demand for these facilities.

Q: Are you endorsing the Parkway West gate station, Segment A, and the Union Gas facilities?

A: No. I am not taking any position on the net benefit of these facilities, other than that those benefits that are cited by the proponents are not likely to be critically

[3] Concerns about increased reliance on U.S. shale gas may erode the economic justification for these facilities, but those issues are beyond the scope of my testimony.

affected by load reductions. The Board may want to review the wisdom the investments to increase imports of U.S. gas, considering such factors as the following:

- The environmental effects (fugitive methane emissions, water use, and pollution) associated with the fracking and other technologies necessary to produce additional gas from the tight shales that would produce most incremental U.S. gas supply.
- The uncertainty of future price differentials between natural gas supplies from western Canada and the U.S. Midwest. That uncertainty would be driven in part by uncertainty in the cost of future regulations that would limit the exploitation of shale gas, or require higher levels of environmental protection.

Q: What are your conclusions?

A: My major conclusions are as follows:

- Enbridge's planning process for this set of projects has been severely deficient, particularly in the failure to adequately assess the alternative of maximizing DSM and other load reductions to reduce costs.
- Enbridge has not provided any reason for the sudden urgency in reducing pressure on the existing pipelines, and certainly no explanation sufficient to justify spending hundreds of millions of dollars.
- The pipeline facilities that Enbridge has identified as Segment B (comprising Segment B1, the Buttonville Station and Segment B2) appear to be avoidable through load reductions. Reinforcements that Enbridge has identified in the GTA for 2017–2020 would also be avoidable, as would additional reinforcements that would otherwise be required after 2020.

- The benefit of deferring Segment B and subsequent reinforcements would be substantial, and would be additive to the commodity and upstream costs avoidable through DSM.
- The deferral of Segment B would require that the Company's forecast of design peak load in the project area be reduced by the equivalent of about 26 thousand cubic meters per hour (10^3m^3/hr.) annually.
- The load in the relevant area may be decreased by a combination of (1) accelerated DSM; (2) expansion of interruptible or curtailable rates for industrial, commercial and apartment loads; and (3) arrangements to reduce the load of the Portlands Energy Centre, a large combined-cycle power plant served from Station B, on winter design-peak days.
- Energy Futures Group has estimated an achievable annual DSM potential in the GTA area (beyond what is in Enbridge's DSM forecast) of 23 10^3m^3 at design peak hour, for an enhanced DSM effort that attains results comparable to those achieved in other jurisdictions. The analyses by Enerlife, on behalf of Environmental Defence, suggest that bringing the Company's DSM program to the top quartile of performance would reduce design-peak load by about 30 10^3m^3/hr. each year. These load reductions would eliminate most or all of the load growth that Enbridge expects to create a supply problem at Station B; a curtailable arrangement with PEC and/or enhancement of the interruptible load program would be available to smooth the transition and top off any shortfall in DSM deployment.

III. The Company's Planning Process

Q: Was the Company's planning that led to the proposed GTA Project adequate?

A: No, in the following respects.

First, Enbridge has known since at least 2002 that continued peak-load growth would result in decreasing pressures along the Don Valley line and eventually require some reinforcement of that line. Yet Enbridge has not attempted to maximize cost-effective load reductions to defer that problem.

Second, Enbridge has operated the pipelines at their current operating pressures for decades without planning for load reductions that would reduce the maximum pressures required as the lines aged. In this filing, Enbridge has suddenly declared that the operating pressures are too high and must be reduced as fast as feasible, where "feasible" is limited to construction of new facilities and not to load reductions.[4]

Third, more generally, Enbridge has not analyzed the ability of incremental load reductions to defer any capital facilities.

Fourth, Enbridge has restricted spending on DSM that would be cost-effective based on its ability to reduce supply costs, and has not even identified the magnitude of potentially avoidable local reinforcement costs or the benefits of reducing operating pressure.

Fifth, Enbridge does not appear to have promoted cost-effective use of interruptible rates to trim rare design-condition peaks and reduce total costs.

[4] Both this problem and the previous one may be examples of "too early, too early, too late," a common utility strategy for delaying alternatives to the utility's preferred strategy until the utility can claim it is too late to implement the alternatives.

Sixth, Enbridge has not even investigated the opportunity of developing a curtailment agreement with Portlands Energy Centre to reduce peaking supply costs and local facilities costs.

Seventh, the Company's analysis for this proceeding has not considered the compatibility of its plans and alternatives with Federal and Provincial greenhouse-gas policy. That would include the effect on carbon and methane emissions of purchasing gas from the U.S. rather than Western Canada, the difference in emissions between strategies with differing amounts of DSM, and the greenhouse benefits of continuing use of the TCPL mainline for gas, rather than increasing use of oil from the tar sands.

Eighth, Enbridge does not appear to have evaluated the economic risks of the proposed expenditures to increase reliance on U.S. gas from tight shale formations, given uncertainties in future resource potential and environmental costs.

Q: What are the practical effects of the problems you identify?

A: There are two categories of effects. First, many of these problems result in the analysis supporting the current application to be incomplete, leaving the Board to make decisions with limited information.

Second, some of the problems that the GTA Project is intended to solve are products of the Company's failure to highlight the load-related constraints on the system years earlier and adapt its planning appropriately. With more-vigorous DSM activity over the last decade, and with increased attention to designing and promoting interruptible rates for relief of distribution peak loads, the need for capacity expansion may well have been entirely and cost-effectively avoided.

Third, Enbridge has missed the opportunity to address broader energy goals in its response to load supply constraints. In particular, Ontario's 2007 Climate Change Action Plan set an objective of reducing greenhouse-gas emissions 15% from 1990 to 2020 and 80% by 2050.[5] The Annual Greenhouse Gas Progress Report 2012 (p.13) found that efforts are falling short of these targets.[6] "Unfortunately, the Ontario action plan and targets have not been adjusted to reflect this new understanding of the climate system" that the previous target of 450 ppm of carbon dioxide will not maintain "global climate conditions similar to those in which our ecosystems and our civilization have evolved." In the building sector, the Progress Report (p. 4) found that "emissions due to natural gas consumption remain a significant barrier to future progress." More generally, the Environmental Commissioner found that greater efforts are necessary:

> The Ontario government indicates that progress has been made toward meeting the 2014 and 2020 targets, primarily by phasing out the use of coal for electricity generation. The coal phase-out is a significant commitment that, on its own, takes Ontario most of the way toward meeting the 2014 target and at least halfway toward the 2020 target. Unfortunately, the ambition displayed in the electricity sector has not been matched in other areas over the past year, and the Ontario government will not reach its 2020 emissions target without additional policy action. The government, itself, has projected a 30 Mt gap by 2020. (p. 14)

Q: How should the Board respond to these issues?

[5]"Go Green: Ontario's Action Plan on Climate Change" PIBS 6445e. Province of Ontario, 2007.

[6]"A Question of Commitment: Review of the Ontario Government's Climate Change Action Plan Results" Annual Greenhouse Gas Progress Report 2012, Environmental Commissioner of Ontario Gord Miller, December 2012.

A: The Board should require regular reports from the gas utilities regarding emerging and anticipated delivery constraints and reinforcements being planned to alleviate those constraints. The Board should require that the utilities integrate demand and supply options, including DSM and interruptible and curtailable rates and contracts, along with adding delivery facilities and local peaking supplies, to relieve that constraint. This process would effectively institute a form of local least-cost planning. A similar approach has been successful for dealing with local constraints on the electric system in Vermont and elsewhere.

More broadly, the Board should require the utilities to re-examine the potentially deferrable local delivery investments and include the benefit of deferral in its avoided costs for DSM.

Finally, the Board should reconsider the budget limitations on DSM, in light of the ability to defer investments and the need to reduce the "emissions due to natural gas consumption [that] remain a significant barrier to future progress" on greenhouse-gas reductions.

Q: Why would special efforts be necessary to encourage gas utilities to pursue cost-effect DSM?

A: There are a number of reasons that utilities may prefer capital projects to DSM, including the interest in growing rate base and the size of the company, experience and confidence with facility additions, institutional inertia, and the effect of the upstream interests of the utility and its affiliates.

IV. Costs Avoidable through Load Reduction

A. Avoidable Facilities

Q: Which facilities in the GTA Project are potentially avoidable by load reductions?

A: Segment B2 and, possibly, Segment B1 and the Buttonville Station are potentially avoidable.

Q: What is the Company's stated justification for Segment B2?

A: Enbridge identifies the need for Segment B2 as being driven by load growth and the resulting decline in pressure at Station B under design conditions (Exhibit A.3.1, p. 4; Exhibit A.3.4, pp. 6–7) and by the Company's desire to reduce pressure on the Don Valley line (Exhibit A.3.3, pp. 17–18).

With regard to load growth, Enbridge says that new pipeline facilities are needed by the 2015/16 winter season to avoid a projected shortfall in gas delivery capacity to Station B, which would impair the Company's ability to meet firm customer requirements in the downtown core and to supply the full contract quantity to the Portlands Energy Centre generating station (PEC). (I.A1.Enbridge.BOMA.32) Enbridge estimates that the capacity deficit at Station B under peak day design conditions would be 4 TJ per day in 2013-14, 7 TJ per day in 2014-15, and 11 TJ per day in 2015-16 (Exhibits JT2.17 and A1.Enbridge.GEC.5).

Q: Have you reviewed the Company's claims regarding load growth along the Don Valley?

A: To a limited extent I have. Enbridge's documentation of its load forecast is limited, and I have not been able to conduct detailed discovery and analysis in the time frame available in this proceeding.

As a result, it is difficult to assess the reasonableness of the Company's projection of load growth along the Don Valley and the reduction in pressure at Station B. Nevertheless Enbridge acknowledges that load reductions, particularly in the areas supplied by the Don Valley line, would reduce the need for Segment B2 to maintain pressure at Station B.[7]

Q: What is EGD's rationale for Segment B1?

A: As I understand the Company's Application, Segment B1 is justified on the basis that it would facilitate the following benefits:

- The commodity and capacity savings from bringing U.S. gas from Parkway West to the Don Valley line and hence south to the city centre, replacing gas from the TCPL mainline at Victoria Square. (Exhibit A.3.5 pp. 20–21; Exhibit A.3.6. pp. 8–9)
- Reducing pressure on the NPS 26 Parkway line and the Don Valley line.

Q: Is Segment B1 justified by the cost reductions associated with increased purchases of U.S. gas?

A: That is not clear, for two reasons.

[7] Enbridge's case for Segment B2 to relieve the pressure shortfall at Station B is not completely clear. According to JT2.25 Table 3, with Segment B1 in place, delivering gas into the Don Valley pipeline at a new interconnection located 9.4 km downstream of Victoria Square Station (A1.Enbridge.GEC.4), design-condition pressure at Station B would be 314 psi, well over the 175 psi required at the Station B outlet, if the operating pressure at Victoria Square is kept at current level. Even if the operating pressure at Victoria Square were reduced to the Company's target, Station B pressure at design conditions would be only be a little low, were no demand reductions pursued.

First, it appears that most or all of the Company's projected purchases of U.S. gas could flow into the GTA even if just Parkway West and Segment A were constructed. Under those circumstances, Enbridge projects that the Parkway stations and Lisgar (where the U.S. gas would be delivered from Union and TCPL) would serve more than 2,040 10^3m^3/hour (Exhibit I.A1.Enbridge. BOMA.25 Attachment 2).[8] In contrast, Victoria Square Station would provide 943 10^3m^3/hour without any additional supplies to the Don Valley line (Exhibit I.A1.Enbridge.BOMA.25 Attachment 1). Hence, so long as Enbridge purchases at least 30% of its peak-day supply for the GTA to be delivered from the TCPL facilities to Victoria Square Station, the portion of the Company's supply that flows from the U.S. can be taken entirely through the Parkway stations and Lisgar, without Segment B.

While Enbridge intends to continue to purchase substantial peak-day supplies from TCPL (856 Tj/day of STFT, Long Haul and STS, from Exhibit A.3.5 Table 1), it is not clear what portion of that would flow to the GTA.

At the much lower loads that prevail at almost all times, even larger amounts of U.S. gas from Parkway would be able to flow through the Parkway and MSL pipelines into the areas supplied by the Don Valley line during peak periods. In addition, Enbridge is moving away from using TCPL gas for seasonal supply, but increasing its use for TCPL for baseload supply. Exhibit JT1.10 shows Enbridge planning to take 33.6% of its gas in 2016 from Western Canada

[8] I netted out the 827 10^3m^3/hour delivered to the Buttonville and Johnsville XHP stations, from Segment B. Without Segment B, Exhibit I.A1.Enbridge.BOMA.25 Attachment 1 appears to show 440 more 10^3m^3/hour flowing east on the XHP system from Keele/CNR (and hence from the Parkway and Lisgar stations), so the total might be more like 2,480 served from the Parkway and Lisgar complex.

through TCPL. Hence, it does not appear that the absence of Segment B would restrict use of U.S. gas commodity on an annual basis.

Thus, Enbridge has not demonstrated that the absence of Segment B would constrain its supply plan or increase its supply costs.

Second, Enbridge has not demonstrated that Segment B1 is the least-cost option for delivering U.S. gas to the Don Valley line. While the situation is in flux, it appears that Segment A would carry gas for TCPL, Union Gas, and/or Gaz Métro as far as Albion, from which one or more of those parties would build a further line to Maple Compressor Station, on the TCPL mainline.[9] That line could be sized to carry some of the Company's U.S. gas from the end of Segment A at Albion to Maple, from which it could flow to Victoria Square Station and then south on the Don Valley line, displacing western-Canada gas that currently flows from Maple to Victoria Square Station. Any incremental cost of building a larger pipeline from Albion to Maple might well be less than the cost of building Segment B1 as a separate line. Enbridge has not provided any analysis of the incremental supply-cost benefits of Segment B1.

Hence, it is not clear that Segment B1 is needed (or cost-effective) as a solution to any bottleneck in delivery of U.S. gas to the GTA.

Q: Has Enbridge provided justification for building Segments B1 and B2 to reduce pressure on the Don Valley and Parkway North pipelines?

A: No. These pipelines have operated at the current pressures throughout their lives, reaching back to the late 1960s. The pipeline pressure issue does not

[9] Union Gas has indicated intent to build this line, if TCPL does not. ("Union, either alone or in a joint venture with Gaz Metro, is committed to building the Albion-Maple pipeline," Notice of Motion, June 21, 2013) Union and Gaz Métro have moved for a stay of the GTA Project and a Board order requiring that Segment A be sized to accommodate their incremental loads to Albion.

appear to have prompted any actions by Enbridge and has only come into this case as a supplemental justification for facilities that Enbridge wants to build for other reasons. Enbridge has not provided any evidence of an actual problem with these operating pressures.

I find it particularly interesting that Enbridge has not presented any evidence that it has been systematically reducing the pressure at the supply end of the lines (such as at Victoria Square Station and Keele/CNR) during low-load periods, even though lower supply pressures would be adequate to supply the delivery stations at the lower loads that prevail for most of the year. Instead, Enbridge seems to be running the system for most or all of the year at pressures that would only be needed under design peak conditions.[10] Enbridge acknowledges that it modifies operating pressures, but emphasizes reductions to accommodate maintenance times or gas flow patterns, not as a regular practice to reduce pressure.

> The Operating Pressure varies due to a number of operating and load conditions. The Operating Pressure is changed on a regular basis by our Gas Control group to meet contract supplies of gas and to move the gas to different parts of the network. The Operating Pressure is often changed when major projects work is undertaken or for running internal inspection tools. The Operating Pressure is sometimes changed due to temporary restrictions in pressure while integrity assessments are undertaken. The Operating Pressures can also fluctuate as customer and weather conditions change during summer and winter conditions. (Exhibit I.A1.Enbridge.BOMA.8(b); also paraphrased in June 12 Tr. pp. 32–33)

It is not clear whether the last sentence means "the setpoints at the origin of the gas (such as Victoria Square and Keele/CNR) are varied intentionally to minimize pressure while meeting customer load," or "pressures downstream

[10] For most of the lines' lives those pressures were not needed even at peak.

fluctuate due to load, even though Enbridge keeps the input pressure constant." Interestingly, Exhibit I.A1.Enbridge.BOMA.8(c) indicates that the pressure on the Don Valley line is kept constant throughout the winter and that the pressure on the NPS 26 Parkway line is kept constant throughout the year, regardless of the wide variation in load within and between seasons.

In any case, Enbridge has not pursued DSM or interruptible load arrangements to allow it to reduce the pressure set points.

B. Costs of Avoidable Facilities

Q: Are the costs of facilities avoidable through load reductions significant?

A: Yes. As detailed in the following subsections, significant avoided costs, in the range of many millions of dollars annually, are associated with the deferral or avoidance of Segment B, related facilities and anticipated reinforcements. Adding these benefits to the avoided upstream gas supply costs would increase the net benefit of accelerated DSM acquisition.

1. Facilities in this Application

Q: What capital costs does Enbridge estimate for the facilities you have identified as potentially avoidable?

A: From Exhibit C.2.1, I compute that the Company's estimate of the costs (including an allocation of contingency, escalation and interest during construction) would be about [redacted] million for Segment B1, and [redacted] million for Segment B2. These are significant capital investments.

Q: What are the annual avoided costs for those facilities?

A: I estimate that the annual capital-cost recovery on a nominally-levelized basis would be about [redacted] million for Segment B1 and [redacted] million for Segment B2, or [redacted] million for Segment B as a whole. On a real-levelized basis (i.e., the 2015 cost that, with inflation, would have the same present-value over the life of the project as the stream of annual revenue requirement), and including O&M and continuing capital additions, the costs would be about [redacted] million for Segment B1 and [redacted] million for Segment B2, or [redacted] million for Segment B as a whole.

Assuming that the DSM load reductions are spread evenly over the entire load of the GTA, which Enbridge expects to grow annually at 26 $10^3 m^3$/hour (see Section V), the avoided cost would be about [redacted] per m^3/hour on design peak or roughly $0.[redacted]/$m^3$ on an annual basis for average retail load in the first year, declining as the required cumulative load reduction rises, with a real-levelized value of about $0 [redacted]/$m^3$ over 15 years. The avoided cost for DSM concentrated in the downtown area or around Station B would be higher, as would the avoided cost for heating load.

2. *Future Reinforcements*

Q: What other facilities has the Company's identified as being related to load growth in the GTA?

A: In Exhibits E.1.1 and I.A1.Enbridge.GEC.42, Enbridge identifies about $12.6 million in annual GTA reinforcements in 2017–2020. It is not clear exactly what amounts and locations of load growth drive these reinforcements, or whether

Enbridge has fully evaluated the need for reinforcements from 2020 onward.[11] It is thus not clear whether the $12.6 million in annual reinforcements is representative of long-term avoided costs, but for comparison, Enbridge reported GTA reinforcements of $11.6 million in 2012 and $21 million in 2013.

If the $12.6 million per annum is typical of load-related reinforcements, driven by GTA-wide annual peak load increases of about 26 10^3m^3/hour (Exhibit JT2.28), the avoided cost of routine load-related reinforcements would be about $480 per m^3/hour on design peak or roughly $0.23/$m^3$ on an annual basis for average retail load. Again, the avoided cost for heating load and for load targeted to the affected area may be higher.

V. Potential Magnitude of Required Load Reduction

Q: What amount of load reduction might be necessary to eliminate the load-related justifications for Segment B?

A: The required load reduction would depend on the location of future load growth and load reductions. Enbridge defines the GTA Project Influence Area to be

> the areas of the Enbridge distribution network where growth had a direct impact on the pressures at the current point of minimum system pressure, located at Station B. The municipalities identified within this area include Scarborough, North York, Toronto, Etobicoke, Brampton, Mississauga, Markham, Richmond Hill, and Vaughan. (Exhibit A.3.4 ¶4)

However, the peak day gas flows in BOMA.25 Attachment 1 suggest that less than 30% of the GTA influence area load is served through Victoria Station and the Don Valley line. It is not clear how much load growth or reductions

[11] Exhibit E.1.1 does not show any reinforcements after 2020, which seems unlikely if load continues to grow.

along Parkway North or in Mississauga would affect pressure at Station B, but it would appear to be less than the effect of reductions at PEC or in the section of downtown Toronto served from Station B.

At worst, if no new facilities were built and the load reductions were spread evenly across the GTA Influence Area, Enbridge estimates that 77,811 10^3m^3 of annual DSM load reductions would be required each year to offset all load growth (Exhibit I.A4.Enbridge.ED.14(b)). This value appears to have been backed out of the ratios of peak hour, peak day and annual load reductions estimated for the Company's existing DSM program, from Exhibit I.A4.Enbridge.ED.14(a). Specifically, Enbridge uses a ratio of 0.00033 m^3 at peak per annual m^3, which is lower than the ratios that Enbridge estimates for all classes except industrial. Reversing that process, I estimate that Enbridge is forecasting a need for about 26 10^3m^3/hour of load reduction spread throughout the GTA area, under design-peak-hour conditions.

If load reductions are concentrated in the area served from the Don Valley line, especially around Station B and the downtown, less than 26 10^3m^3/hour of design-hour load reduction would be required. If Parkway West and Segment A reduce the flows down the Don Valley line and west into the downtown, the required load reduction would also be reduced.

VI. Options for Reducing Load

Q: How could Enbridge reduce load on the Don Valley line, to increase pressure at Station B and allow Enbridge to decrease the pressure setpoint at Victoria Square Station?

A: I am aware of three approaches to load reduction that may be applicable in this situation: increasing energy efficiency through demand-side-management (DSM) programs, curtailing supply to the Portlands Energy Centre (PEC), and expanding the use of interruptible or curtailable rates. The potential for load reductions from additional DSM is the subject of the evidence of the testimony filed by the Energy Futures Group for GEC. I will discuss the other two options.

A. Curtailment of the Portlands Energy Centre

Q: Are there reasons to believe that Enbridge could arrange for some interruption of PEC in extremely cold weather conditions, such as the 41 HDD that defines the Company's design peak load?

A: Yes. Portlands Energy Centre does not appear to be required for electric service at winter design peak conditions for three reasons. First, peak electric loads in Ontario occur in the summer; winter peak loads are much lower than summer peak loads. Second, aggregate electric generation capacity is higher in the winter than in the summer, because the capacity of generators is higher in the winter.[12] Third, extremely cold weather often coincides with electric loads that are well below the winter peak electric load.

Q: How large are the differences between Ontario's summer and winter peaks?

[12] In addition, the neighboring systems of Michigan and New York are summer-peaking and have more capacity available to Ontario in the winter.

A: As shown in Table 1, Ontario is expecting summer peak to exceed winter by about 1,400 MW by 2015, rising to 1,900 MW in 2022.[13]

Table 1: Ontario Peak Load Projections, MW

	Summer	Winter	Difference
2013	23,301	22,192	1,109
2014	23,080	21,890	1,190
2015	22,859	21,500	1,359
2016	22,638	21,153	1,485
2017	22,471	20,719	1,752
2018	22,583	20,700	1,883
2019	22,891	21,063	1,828
2020	23,010	21,234	1,776
2021	23,390	21,441	1,949
2022	23,442	21,529	1,913

Source: 2012 Long-Term Reliability Assessment, Appendix I. North American Electric Reliability Council, November 2012.

This difference in 2015–2022 is 250% to 350% of the 550 MW capacity of PEC.

Q: How large are the differences between Ontario's summer and winter resource capabilities?

A: The NERC report provides both low and high estimates of capability (called "Anticipated" and "Adjusted Potential"), and I report both values in Table 2. As shown in Table 2, winter capability exceeds summer capability by over 1,000 MW in six of the eight years 2013/14 through 2022/23, rising to over 4,000 MW

[13] While these values are taken from the annual report by the North American Electric Reliability Council (NERC), the summer load forecasts match the values provided in the IESO's Ontario Reserve Margin Requirements 2013-2017, November 15 2012 (IESO_REP_0846)

in 2022/23. In 2019/20, the winter capacity increment is 400–700 MW, while in 2016/17, winter capacity is somewhat lower than summer capacity.[14]

Table 2: Ontario Electric Capacity Resources by Season

	Summer		**Winter (Starting)**		**Winter Increment**	
	Anticipated	Potential	Anticipated	Potential	Anticipated	Potential
2013	31,938	31,938	32,060	32,074	122	136
2014	30,023	30,035	29,908	30,192	−115	157
2015	29,725	29,962	31,038	31,821	1,313	1,859
2016	28,801	29,455	28,332	29,197	−469	−258
2017	26,937	27,657	28,121	29,886	1,184	2,229
2018	25,858	28,368	27,189	30,150	1,331	1,782
2019	24,777	27,827	25,160	28,528	383	701
2020	23,867	28,509	25,125	30,085	1,258	1,576
2021	22,787	28,820	26,014	32,364	3,227	3,544
2022	22,791	28,996	26,858	33,380	4,067	4,384

Source: NERC 2012 LTRA p. 68 et seq.

Q: What effect does the lower winter load and higher winter capability have on the reserve margin in the winter?

A: The winter reserve margin is much higher than the summer reserve margin. As summarized in Table 3, the 2012 Long Term Reliability Assessment shows that Ontario has anticipated winter reserve margins greater than 18% (and usually greater than 20%) through the end of its study period in 2022/23, while the anticipated summer reserve margin drops below 20% in 2017 and would become negative in 2021 and 2022.[15] Adding capacity to keep the summer margin above the reference target (in the Adjusted Potential case) results in winter reserve margins in 35% to 55% range.

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[14] These two years may reflect the scheduling of capacity retirements (after one summer's peak) and addition of replacement capacity (before the next summer's peak).

[15] The NERC Reference reserve margin is NERC's estimate of required installed reserves.

Table 3: Ontario Seasonal Reserve Margins

	Summer Reserve Margin				Winter Reserve Margin		
	Anticipated	Adjusted Potential	NERC reference		Anticipated	Adjusted Potential	NERC reference
2013	37.1%	37.1%	19.7%	*2013/14*	44.5%	44.5%	18.6%
2014	30.1%	30.1%	18.6%	*2014/15*	36.6%	37.9%	19.8%
2015	30.0%	31.1%	19.8%	*2015/16*	44.4%	48.0%	19.2%
2016	27.2%	30.1%	19.2%	*2016/17*	33.9%	38.0%	20.0%
2017	19.9%	23.1%	20.0%	*2017/18*	35.7%	44.3%	20.0%
2018	14.5%	25.6%	20.0%	*2018/19*	31.4%	45.7%	20.0%
2019	8.2%	21.6%	20.0%	*2019/20*	19.5%	35.4%	20.0%
2020	3.7%	23.9%	20.0%	*2020/21*	18.3%	41.7%	20.0%
2021	-2.6%	23.2%	20.0%	*2021/22*	21.3%	51.0%	20.0%
2022	-2.8%	23.7%	20.0%	*2022/23*	24.8%	55.0%	20.0%

Q: How large is PEC's gas demand?

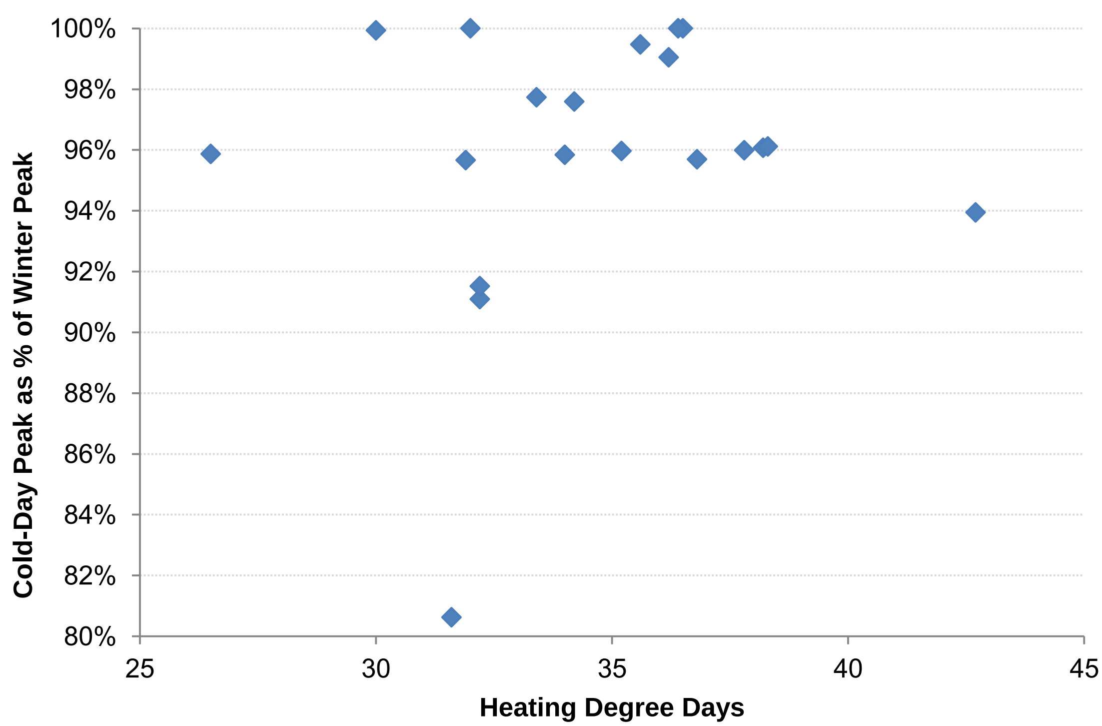
A: I do not know how much gas PEC actually uses at peak. Before the plant was constructed, PEC contracted with Enbridge for delivery of a maximum hourly quantity of 116 10^3m^3 and a contract demand of 2,786 10^3m^3 per day for 20 years (Decision and Order, EB-2006-0305, p. 3). The 116 10^3m^3 per hour that Enbridge assumes it will deliver to PEC under design conditions accounts for nearly 30% of the total hourly delivery requirement at Station B (A1.Enbridge. BOMA.25).

The contract maximum hourly quantity may exceed PEC's actual consumption under design conditions. First, since the PEC service agreement was executed before the plant was construction, the contract quantities must have been based on engineering estimates, not the plant's actual operations. To ensure that the Enbridge facilities were sized to meet the highest potential usage at the plant, it would have been prudent for the PEC developers to use a high-side estimate of the maximum hourly quantity in its transportation service contract with Enbridge. Second, because PEC was required to make an upfront payment to Enbridge to cover the costs of the pipeline facilities needed to be built to provide service to PEC, reducing the contract demand quantity in its transportation services agreement with Enbridge would not have resulted in any savings to PEC. With a lower contract demand, PEC would have been required to increase its contribution in aid of construction to Enbridge, requiring more financing by PEC and less by Enbridge.

Q: Do design weather conditions occur on the same day as maximum winter electric load?

A: Not on any consistent basis. While electric demand is higher on very cold days, maximum electric demand in a year does not generally occur on the coldest day. For each winter 1993–2012, Table 4 plots heating degree days (HDD) maximum hourly load on the coldest day versus peak electric load on that day as a percent of the winter's peak load.

Table 4: Electric Load on Coldest Day as % of Winter Peak Load (1993-2012)

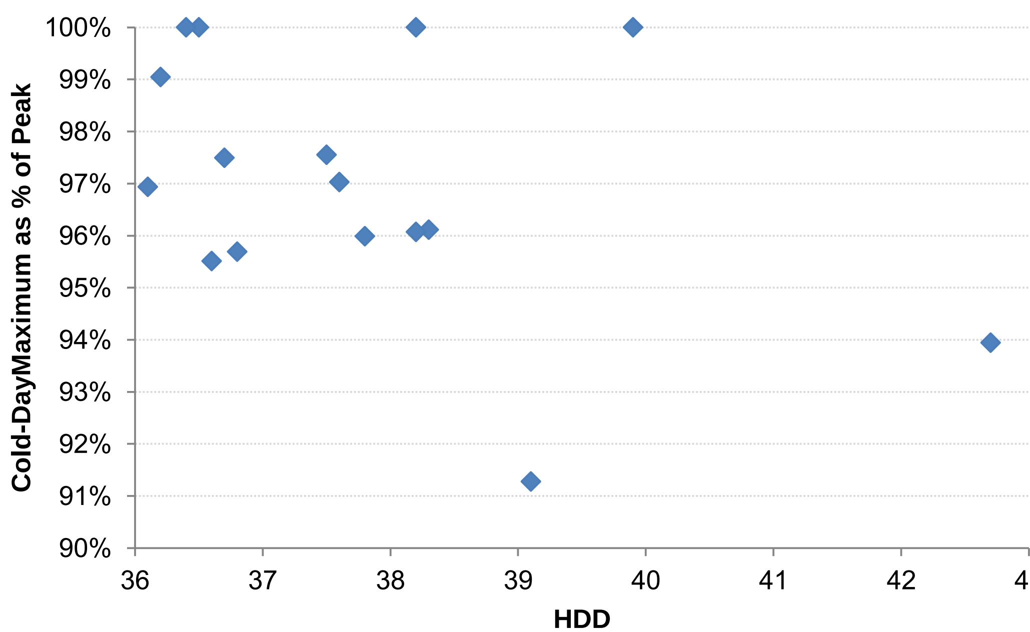


Only three of the last 20 winters experienced the winter peak load on the year's coldest day, and for only three other years was the maximum load on the coldest day within 2% of the winter peak. For most years, the coldest day peak was 94% to 98% of the winter peak. On the coldest day (the one closest to the Company's design criteria), electric load was 6% below the winter peak.

Table 5 shows similar data for the very cold days (over 36 HDD) over the last 20 years, regardless of whether the day was the coldest in the year. Again, only a few of these cold days was the peak electric-load day for the year. Most cold days have peak loads in the 95% to 98% range.

The capacity of PEC is about 2.5% of Ontario's winter electric peak. In most years, the Ontario electric system would have a higher capacity reserve on the coldest winter day without PEC than on the peak winter day.

Table 5: Electric Load on Cold Days as % of Winter Peak Load



Q: Does the peak design hour occur at the same time of day as maximum winter electric load?

A: No. The electric peak load on the coldest days occurs in the evening, between 5 and 7 PM, while the gas peak load typically occurs at 7 AM.

> The demand on the Enbridge system is a bimodal consumption with a peak occurring in the morning and again in the evening. The peak hour refers to the morning peak and is approximately 20% higher than the average hourly flow.… The morning peak is at its maximum between 7 and 8 AM. (Exhibit I.A1.Enbridge.GEC.17)

Combining the lower winter peak, the higher winter capacity, the difference between electric load on the coldest day and on the winter peak day, and the difference in timing between electric peak and gas design conditions, Ontario should be able to operate without any of PEC's capacity on the very coldest days.

Q: How does the PEC contract load compare to the load reductions required to eliminate the load-related justification for Segment B?

A: As I computed in Section V, the required annual load reduction over the GTA Influence Area is about 26 $10^3 m^3$/day. The required reduction at Station B would be less than 26 $10^3 m^3$/day. The 116 $10^3 m^3$ of PEC's contract load is thus more (and perhaps much more) than four times the annual required load reduction. Arrangement for curtailment of PEC would thus offset the Company's anticipated load growth in the next couple years, as DSM and interruptible load programs ramp up, leaving large amounts of potential curtailment for future years.[16]

Q: Has Enbridge reviewed the feasibility of contracting with PEC or Ontario Power Authority for curtailment of PEC at or near design conditions?

[16] Of course, since very cold weather is rare, PEC might not experience any curtailment for many years.

A: No. Despite its concerns about low pressure at Station B, through which PEC is served, and about the pressure required at Victoria Square, Enbridge admits that it has not considered this option:

> Enbridge does not have any information regarding the ability of PEC to operate on alternate fuels.
>
> Enbridge does not have any information on the feasibility of PEC converting to alternate fuels.
>
> Enbridge has not approached PEC regarding an interruptible delivery tariff and has no plans to do so. (Exhibit I.A1.Enbridge.GEC.7)

B. Interruptible or Curtailable Rates

Q: How could rate design contribute to reducing loads on the Don Valley line and increasing pressure at Station B?

A: Both interruptible and curtailable rates, designed to offer incentives for customers to be able to eliminate or reduce gas load under peak load conditions, would have these benefits. For the purposes of avoiding local facility expansion and the need to contract for peaking supplies, load reductions would be needed very rarely, perhaps a few days every few years. That sort of service could be accepted by the following two types of customers:

- *Apartment and commercial buildings and industrial customers that can switch their boiler load to an alternative fuel.* If that fuel is much more expensive than gas (which is the case at present), the customer may not be interested in switching frequently, but the cost of the alternate fuel is not very important for infrequent fuel switching.[17]

[17] The customer may not be able to interrupt its entire load (e.g., an apartment building would need to maintain adequate supply for ranges, dryers and perhaps water heaters), so options of curtailing load are important.

- Some industrial customers, given some notice, may be able to shut down a gas-hungry process for a period of hours or a day, especially since extremely cold weather is generally foreseen some time in advance, allowing for changes to production plans.

Q: What sorts of customers use the Company's interruptible rates?

A: Enbridge has no information on that issue.

> Company does not track / have specific information on whether the interruptible load is related to space heating, industrial boiler or industrial type processes. (Exhibit I.A1.Enbridge.GEC.23b(iii))

> The Company does not track / have specific information on whether the interruption is achieved by switching to an alternate fuel or by reduction in process output. (Exhibit I.A1.Enbridge.GEC.23b(iv))

Q: Do the Enbridge interruptible rates reflect any benefit related to reduced distribution costs or increased reliability?

A: No. As Enbridge explains, only supply costs are considered:

> The value of interruptible credits generally reflects the difference in the cost of the Company's gas supply portfolio with interruptible load available to the Company and the scenario that assumes all customers take firm service. (Exhibit I.A1.Enbridge.GEC.23c(ii))

Q: Does Enbridge allow for curtailment of loads, rather than full interruption of customer load?

A: No. Both Rate 145 and Rate 170 limit applicability to "a single terminal location …which can accommodate the total interruption of gas service when required by the Company." The tariff defines "terminal location" as "The building or other facility of the Applicant at or in which natural gas will be used by the Applicant." Hence, the customer cannot determine which processes to curtail to meet a load-reduction obligation, but must shut off all the load at its location. If

Enbridge enforces this language literally, a customer could not even have interruptible service for one process and firm service for other processes.[18]

Q: Has Enbridge provided any evidence regarding the feasibility of avoiding any facilities investment or reducing operating pressures by increasing the amount of load that is interruptible at or near design conditions?

A: No.

Q: Does this conclude your testimony?

A: Yes.

[18] Enbridge reports "forecast design peak day volumes" of 382.7 $10^3 m^3$ for Rate 145 and 235.9 $10^3 m^3$ for Rate 170 (Exhibit I.A1.Enbridge.APPrO.5).