EB-2015-0049

Ontario Energy Board

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

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. pursuant to Section 36(1) of the *Ontario Energy Board Act, 1998,* S.O. 1998, for an order or orders approving its Demand Side Management Plan for 2015-2020

ENBRIDGE GAS DISTRIBUTION INC.
COMPENDIUM OF MATERIALS
FOR CROSS-EXAMINATION OF
GREEN ENERGY COALITION

August 31, 2015

ENBRIDGE GAS DISTRIBUTION INC.
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Ministry of Energy

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Ontario

MAR 3 1 2014

Mr. Colin Andersen
Chief Executive Officer
Ontario Power Authority
1600-120 Adelaide Street West
Toronto ON M5H 1T1

Dear Mr. Andersen:

Re: 2015-2020 Conservation First Framework

I write in my capacity as the Minister of Energy in order to exercise the statutory power of ministerial direction I have in respect of the Ontario Power Authority (OPA) under the *Electricity Act, 1988,* as amended (the "Act").

Background

In *Achieving Balance: Ontario's Long-Term Energy Plan* (LTEP 2013), released on December 2, 2013 the Government established a provincial conservation and demand management (CDM) target of 30 terawatt hours (TWh) in 2032. To assist the Government in achieving this target, LTEP 2013 also committed to establishing a new six-year Conservation First Framework beginning in January 2015, replacing the one that is currently winding down. The new Conservation First Framework will enable the achievement of all cost-effective conservation and foster innovation through information sharing and the adoption of new technologies and approaches, including innovative performance management structures to drive greater energy savings.

To remain on track to achieve the LTEP 2013 CDM target, it is forecasted that 7 TWh needs to be achieved between 2015 and the end of 2020 through Distributor CDM programs enabled by the Conservation First Framework. In addition, transmission connected customers will continue to have access to OPA CDM programs.

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To this end, I have issued a directive to the Ontario Energy Board (the "Board") (the "CDM Directive"), instructing it to amend the license of each licensed electricity distributor (Distributor) to add a condition that specifies the Distributor shall, between January 1, 2015 and December 31, 2020, make CDM programs available to customers in its licensed service area and shall, as far as is appropriate and reasonable having regard to the composition of the Distributor's customer base, do so in relation to each customer segment in its service area (CDM Requirement). Such Distributor CDM programs are required to achieve reductions in electricity consumption.

Each Distributor will be required to meet its CDM Requirement by:

i. making a core set of province-wide CDM programs, funded by the OPA, available to customers in its licensed service area (Province-Wide Distributor CDM Programs);
ii. making local and/or regional CDM programs, funded by the OPA, available to customers in its licensed service area (Local Distributor CDM Programs); or
iii. a combination of (i) and (ii).

Direction

Therefore, pursuant to my authority under section 25.32 of the Act, I hereby direct the OPA to coordinate, support and fund the delivery of CDM programs through Distributors to achieve a total of 7 TWh of reductions in electricity consumption between January 1, 2015 and December 31, 2020 in accordance with the following guiding principles and requirements.

GUIDING PRINCIPLES

The OPA shall implement this direction according to the following principles:

1. Distributors are the face of electricity conservation to their customers in all sectors.

2. Distributors will be provided with long term, stable funding to provide the certainty they need to implement CDM programs.

3. Customers will be given more CDM program choice along with streamlined oversight and administration.

4. Distributors will have accountability for meeting their assigned CDM targets and will be provided the authority and means for meeting them cost-effectively.

5. Innovation and the adoption of new technologies will be encouraged.

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6. While there will be CDM programs available for all residential, commercial and industrial sectors, the value of CDM investments may be higher in some sectors than others.

7. There will be renewed efforts to deepen consumer awareness of CDM and how it relates more broadly to the electricity system.

8. CDM programs for low-income residential customers will be improved.

9. The role of Distributors in the delivery of CDM programs to on-reserve First Nation customers will be enhanced.

10. Distributor CDM programs will result in the full achievement of 7 TWh of electricity savings.

11. Approvals and administrative requirements will be streamlined to provide Distributors flexibility to design, deliver and administer CDM programs to their customers.

12. OPA will provide support to Distributors in the design and delivery of CDM Programs.

REQUIREMENTS

1. GOVERNANCE

1.1 The OPA shall manage its relationship with Distributors through new streamlined contracts on a non-competitive basis. The OPA will work with Distributors to put such contracts in place by January 1, 2015.

1.2 The OPA shall provide support to Distributors to assist them in submitting their CDM Plans, as outlined in section 3, to the OPA no later than May 1, 2015 for approval. The OPA shall continue to make 2011-2014 OPA contracted Province-Wide CDM Programs available to customers through their Distributor until the Distributor's CDM Plan is approved by the OPA.

1.3 The OPA shall provide Distributors with flexibility to design, deliver and administer Province-Wide Distributor CDM Programs and Local Distributor CDM Programs.

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1.4 The OPA shall establish a budget to achieve 7 TWh of electricity savings over the six-year period, based on current system planning projections. The budget and 7 TWh target will be reviewed as part of the mid-term review, as described in section 6, and revised as needed based on achievable cost-effective conservation and system planning projections at the time.

1.5 The OPA shall establish a budget allocation for each Distributor in consideration of the Distributor CDM Target and CDM Plan as outlined in sections 2.2 and 3.

1.6 The OPA shall, in consultation with Distributors, develop a cost recovery and performance incentive mechanism for Distributors for making Province-Wide Distributor CDM Programs and/or Local Distributor CDM Programs available to customers in their service areas. For each Province-Wide Distributor CDM Program and Local Distributor CDM Program within the Distributors' CDM Plan, Distributors shall be provided a choice of the following cost recovery mechanisms:

i. **Full Cost Recovery:** The Distributor shall be paid the full amount of prudently incurred costs for the administration and implementation of its Province-Wide Distributor CDM Program and/or Local Distributor CDM Program, subject to the Distributor achieving a specified minimum level of its Distributor CDM Target. The OPA shall report back by July 1, 2014 with recommendations on administrative or financial consequences of Distributor underperformance, should it occur. A tiered performance incentive mechanism shall be made available to Distributors with incentives beginning to accrue once a Distributor achieves 100% of the portion of its Distributor CDM Target allocated to the full cost recovery mechanism, in amounts determined by the OPA in consultation with Distributors.; or

ii. **Pay for Performance:** The Distributor shall be paid for the administration and implementation of its Province-Wide Distributor CDM Program and/or Local Distributor CDM Program, corresponding to the portion of the Distributor CDM Target allocated to the pay for performance mechanism, based on a pre-specified value for each verified kilowatt hour of electricity savings achieved, in amounts determined by the OPA in consultation with Distributors.

1.7 The OPA shall, subject to necessary regulatory amendments, recover payments made under the Province-Wide Distributor CDM Programs and Local Distributor CDM Programs from the Global Adjustment Mechanism up to the budget established under section 1.4.

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1.8 The OPA shall ensure that its contracts with Distributors include clauses allowing for corrections and changes in each Distributor CDM Target, as outlined in section 2.2, and in Distributor budgets which may be required in accordance with a mid-term review as outlined in section 6.

2. DISTRIBUTOR CDM TARGETS

2.1 The OPA, in consultation with Distributors, shall develop an allocation methodology to allocate the full 7 TWh among Distributors. The allocation methodology may take into consideration Distributor CDM potential at a local and/or regional level as identified in the OPA's 2014 energy efficiency achievable potential study, and other factors, as appropriate.

2.2 The OPA shall allocate to each Distributor a numeric CDM target ("Distributor CDM Target") to achieve reductions in electricity consumption for all customer segments in the Distributor's licensed service area.

2.3 The OPA shall encourage Distributors to aggregate Distributor CDM Targets with neighbouring Distributors to develop 21 regional CDM targets for the period January 1, 2015 to December 31, 2020. The OPA shall encourage Distributors to work cooperatively to develop regional CDM Plans to meet the regional CDM targets.

2.4 The OPA shall evaluate Distributor achievement of electricity savings on an annual incremental basis based on the OPA's Evaluation, Measurement and Verification (EM&V) protocols.

3. CDM PLANS AND PROGRAMS

3.1 The OPA shall support Distributors in designing a core set of Province-Wide Distributor CDM Programs for the following segments of distribution system connected customers to make available for delivery in Distributors' licensed service areas:

i. Residential
ii. Low-income
iii. Small business
iv. Commercial (including multi-family buildings)
v. Agricultural
vi. Institutional
vii. Industrial

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3.2 Province-Wide Distributor CDM Programs shall:

i. Be designed by Distributors, with support from the OPA, through working groups. The membership of the working groups shall consist of OPA and Distributor representatives.

ii. Balance the value of flexibility for some program customization to meet local and/or regional needs with the value of offering consistent CDM measures to customer segments across all Distributor service areas.

3.3 The OPA shall support Distributors, as required, in designing Local Distributor CDM Programs, including programs for specific industry concentrations or customer segments in a particular licensed service area and/or region that require unique approaches to achieve electricity savings, such as on-reserve First Nation customers.

3.4 The OPA shall require each Distributor to submit a CDM Plan to the OPA for approval.

3.5 The OPA shall establish a streamlined review and approval process for Distributor CDM Plans and proposals for Province-Wide Distributor CDM Programs and Local Distributor CDM Programs. To facilitate this process, the OPA, in consultation with Distributors, shall establish guidelines that include rules relating to the streamlined review and approval of CDM Plans and proposals for Province-Wide Distributor CDM Programs and Local Distributor CDM Programs. In establishing such guidelines, the OPA shall have regard to the following objectives in addition to such other factors as the OPA considers appropriate:

i. Distributor CDM Plans must provide a description of how the Distributor will achieve its Distributor CDM Target, including but not limited to, a description of the Distributor's year-by-year plan, including milestones for achieving its Distributor CDM Target, a description of Province-Wide Distributor CDM Programs and any Local Distributor CDM Programs, and projected budgets and electricity savings by sector.

ii. The OPA shall establish a service standard of no more than 60 days for review and approval of Distributor CDM Plans and program. Any request by the OPA for additional information during its review will cause the remaining period for approval to be paused and shall resume at such time as the request is satisfied.

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iii. The OPA shall seek to approve unique Local Distributor CDM Programs that avoid marketplace confusion and ensure the prudent use of funds by avoiding duplication of Province-Wide Distributor CDM Programs. The OPA, in consultation with Distributors, shall establish rules on what constitutes duplication.

iv. The OPA shall encourage Distributors to incent CDM measures with relatively longer lifespans and energy savings persistence and shall consider the system value of the measures, including reductions at peak times.

v. The OPA shall ensure there is a positive benefit-cost analysis of each CDM Plan and each Province-Wide CDM Program and Local Distributor CDM Program utilizing the OPA's Total Resource Cost Test and the Program Administrator Cost Test found in the OPA's Cost-Effectiveness Guide, dated October 15, 2010 (OPA Cost-Effectiveness Tests), which may be updated by the OPA from time to time. The OPA will establish hurdle rates to consider the cost of delivering Province-Wide Distributor CDM Programs and Local Distributor CDM Programs against the avoided cost of procuring supply.

vi. The OPA shall, despite section 3.5 (v), allow Distributors to apply to the OPA for approval of Province-Wide Distributor CDM Programs and Local Distributor CDM Programs where cost effectiveness is not demonstrated if the program is:

a) targeted to on-reserve First Nation customers
b) designed for educational purposes
c) a low-income CDM program

vii A Distributor may, despite section 3.5(v), submit a CDM Plan where cost effectiveness is not demonstrated if the Distributor can reasonably demonstrate that it is unable to develop a plan that is cost effective due its size, location, the nature of its customer base or other unusual circumstances. In order to obtain the approval of such a CDM Plan, the Distributor must also demonstrate that:

(a) it has made reasonable efforts to determine if a CDM Plan could be delivered cost effectively in its service area by another Distributor; and

(b) The CDM Plan will be delivered in as cost effective a manner as is reasonably possible.

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viii. The OPA shall take into consideration the cost and the number of First Nation, educational and low-income CDM programs that a Distributor already has undertaken or plans to undertake when approving these CDM programs. Although there is no requirement that First Nation, educational, or low-income programs be cost effective, Distributors shall be required to provide adequate evidence that the CDM programs will likely result in electricity savings and will be delivered in as cost effective a manner as is reasonably possible.

ix. The OPA shall allow Distributors to propose changes and modifications to its CDM Plan on an annual basis, or more frequently.

x. The OPA shall encourage Distributors to maximize administrative and delivery efficiencies by utilizing appropriate program delivery models. Specifically, the OPA and/or Distributors shall provide enhanced co-ordination efforts with regard to:

a) Opportunities to target consumers with multiple locations across several licensed service areas (e.g., national accounts) and CDM measures delivered or promoted through provincial or national channels (e.g., retailer in-store rebates or coupons); and

b) CDM activities, including, but not limited to, the marketing, procurement and delivery of CDM measures and/or services where these will afford significant administrative cost and/or delivery efficiencies (e.g., call centre, rebate fulfillment and appliance de-commissioning).

xi. The OPA shall require Distributors, where appropriate, to coordinate and integrate Province-Wide Distributor CDM Programs and Local Distributor CDM Programs with natural gas distributor ("Gas Distributors") conservation programs to achieve efficiencies and convenient integrated programs for electricity and natural gas customers.

xii. The OPA shall require Distributors, where appropriate, to coordinate and integrate low-income Province-Wide Distributor CDM Programs and Local Distributor CDM Programs with Gas Distributor low-income conservation programs.

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4. MARKETING

4.1 The OPA shall be responsible for province-wide marketing and mass media buying for Province-Wide Distributor CDM Programs under the saveONenergy brand.

4.2 The OPA shall work with Distributors to ensure Province-Wide Distributor CDM Programs and Local Distributor CDM Programs are consistently marketed under the saveONenergy brand, and for local marketing and advertising efforts, co-branded with Distributor logos. The OPA may also work with Distributors to provide them with the advantages of scale (for example, in the purchase of media and the development, production and distribution of marketing material).

4.3 The OPA shall make the saveONenergy brand available to the Gas Distributors for marketing of natural gas conservation programs on terms that the OPA may negotiate with the Gas Distributors.

5. REPORTING

5.1 The OPA shall continue to produce and publish an annual report on overall progress toward achieving the provincial CDM target of 30 TWh, including contributions to the target achieved through Province-Wide Distributor CDM Programs, Local Distributor CDM Programs, demand response programs, programs for transmission connected customers and product codes and standards. The annual report shall cover the period from January 1 to December 31 of the previous year.

6. MID-TERM REVIEW

6.1 The OPA, in consultation with the Ministry of Energy and Distributors, shall no later than June 1, 2018 have completed a formal mid-term review of:

i. the 7 TWh target and the overall budget for achieving that target
ii. allocation of budgets and Distributor CDM Targets
iii. lessons learned on cost recovery and performance incentive mechanisms, and;
iv. CDM contribution to regional planning

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6.2 The OPA shall conduct an achievable potential study for electricity efficiency in Ontario every three-years, with the first study completed by June 1 2016, to inform electricity efficiency planning and programs. The achievable potential study should, as far as is appropriate and reasonable having regard to the respective characteristics of the electricity and natural gas sectors, be coordinated with the natural gas efficiency achievable potential study referred to in the CDM Directive to the Board.

7. DEFINITION OF CDM

7.1 The OPA shall consider CDM to be inclusive of activities aimed at reducing electricity consumption and reducing the draw from the electricity grid, such as geothermal heating and cooling, solar heating and small scale (i.e., <10MW) behind the meter customer generation. However, CDM should be considered to exclude those activities and programs related to a Distributor's investment in new infrastructure or replacement of existing infrastructure, any measures a Distributor uses to maximize the efficiency of its new or existing infrastructure, activities promoted through a different program or initiative undertaken by the Government of Ontario or the OPA, such as the OPA Feed-in Tariff (FIT) Program and micro-FIT Program and activities related to the price of electricity or general economic activity.

8. SUPPORT AND FUNDING FOR RESEARCH AND INNOVATION

8.1 The OPA Conservation Fund provides financial support to new and innovative electricity conservation initiatives designed to enable Ontario's residents, businesses and institutions to cost-effectively reduce their demand for electricity

8.2 The OPA shall continue to provide, through its Conservation Fund, support and funding for new and innovative electricity conservation initiatives, including small scale distribution storage technologies, as a means to assist Distributors and others in their conservation efforts.

9. PEAKSAVERPLUS PROGRAM

9.1 LTEP 2013 committed that Ontario will aim to use demand response to meet 10% of peak demand by 2025, equivalent to approximately 2,400 megawatts under current forecast conditions. To encourage further development of demand response in Ontario, the Independent Electricity System Operator ("IESO") will evolve existing demand response programs in Ontario and introduce new initiatives.

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9.2 A transition plan is currently being developed to evolve existing programs, potentially including the peaksaverPLUS program, to an IESO administered market. Until such time as the transition plan has been finalized, including plans for the peaksaverPLUS program, the OPA shall continue to make the program available to Distributors to deliver to customers in their licensed service areas.

This direction takes effect on the date it is issued.

Sincerely,

Bob Chiarelli
Minister

cc. James D. Hinds, Chair, Ontario Power Authority
Rosemarie T. Leclair, Chair and Chief Executive Officer, Ontario Energy Board
Bruce Campbell, President and Chief Executive Officer, Independent Electricity System Operator
Tim O'Neill, Chair, Independent Electricity System Operator
Serge Imbrogno, Deputy Minister, Ministry of Energy
Halyna Perun, Director, Legal Services Branch, Ministries of Energy and Infrastructure

Ontario
Executive Council
Conseil exécutif

Order in Council
Décret

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and concurrence of the Executive Council, orders that:

Sur la recommandation de la personne soussignée, le lieutenant-gouverneur, sur l'avis et avec le consentement du Conseil exécutif, décrète ce qui suit :

WHEREAS the government adopted a policy of putting conservation first in its 2013 Long-Term Energy Plan, *Achieving Balance.*

AND WHEREAS it is desirable to achieve reductions in electricity consumption and natural gas consumption to assist consumers in managing their energy bills, mitigating upward pressure on energy rates and reducing air pollutants, including greenhouse gas emissions, and to establish an updated electricity conservation policy framework ("Conservation First Framework") and a natural gas conservation policy framework.

AND WHEREAS the Minister of Energy intends to issue a direction to the Ontario Power Authority to require that it undertake activities to support the Conservation First Framework, including the funding of electricity distributor conservation and demand management programs.

AND WHEREAS the Minister of Energy may, with the approval of the Lieutenant Governor in Council, issue directives under section 27.1 of the *Ontario Energy Board Act, 1998* in order to direct the Board to take steps to promote energy conservation, energy efficiency, load management or the use of cleaner energy sources, including alternative and renewable energy sources.

AND WHEREAS the Minister of Energy may, with the approval of the Lieutenant Governor in Council, issue directives under section 27.2 of the *Ontario Energy Board Act, 1998* in order to direct the Board to take steps to establish conservation and demand management targets to be met by electricity distributors and other licensees.

NOW THEREFORE the Directive attached hereto is approved and shall be and is effective as of the date hereof.

Recommended ______________ Minister of Energy

Concurred ______________ Chair of Cabinet

Approved and Ordered MAR 2 6 2014 Date

______________ Lieutenant Governor

O.C./Décret 467 / 2014

MINISTER'S DIRECTIVE

TO: THE ONTARIO ENERGY BOARD

I, Bob Chiarelli, Minister of Energy, hereby direct the Ontario Energy Board (the "Board") pursuant to my authority under sections 27.1 and 27.2 of the *Ontario Energy Board Act, 1998* (the "Act") to take the following steps to promote electricity conservation and demand management ("CDM") and natural gas demand side management ("DSM"):

1. The Board shall, in accordance with the requirements of this Directive and without holding a hearing, amend the licence of each licensed electricity distributor ("Distributor") to establish the following as the CDM target to be met by the Distributor:

    i. add a condition that specifies that the Distributor shall, between January 1, 2015 and December 31, 2020, make CDM programs available to customers in its licensed service area and shall, as far as is appropriate and reasonable having regard to the composition of the Distributor's customer base, do so in relation to each customer segment in its service area ("CDM Requirement");

    ii. add a condition that specifies that such CDM programs shall be designed to achieve reductions in electricity consumption;

    iii. add a condition that specifies that the Distributor shall meet its CDM Requirement by:

        a) making Province-Wide Distributor CDM Programs, funded by the Ontario Power Authority (the "OPA"), available to customers in its licensed service area;

        b) making Local Distributor CDM Programs, funded by the OPA, available to customers in its licensed service area; or

        c) a combination of (a) and (b); and

    iv. add a condition that specifies the Distributor shall, as far as possible having regard to any confidentiality or privacy constraints, make the details and results of Local Distributor CDM Programs available to other Distributors upon request.

2. Despite paragraph 1, the Board shall not amend the licence of any Distributor that meets the conditions set out below:

    i. with the exception of embedded distributors, the Distributor is not connected to the Independent Electricity System Operator ("IESO") – controlled grid; or

    ii. the Distributor's rates are not regulated by the Board.

3. The Board shall establish CDM Requirement guidelines. In establishing such guidelines, the Board shall have regard to the following objectives of the government in addition to such other factors as the Board considers appropriate:

i. that the Board shall annually review and publish the verified results of each Distributor's Province-Wide Distributor CDM Programs and Local Distributor CDM Programs and report on the progress of Distributors in meeting their CDM Requirement;

ii. that CDM shall be considered to be inclusive of activities aimed at reducing electricity consumption and reducing the draw from the electricity grid, such as geothermal heating and cooling, solar heating and small scale (i.e., <10MW) behind the meter customer generation. However, CDM should be considered to exclude those activities and programs related to a Distributor's investment in new infrastructure or replacement of existing infrastructure, any measures a Distributor uses to maximize the efficiency of its new or existing infrastructure, activities promoted through a different program or initiative undertaken by the Government of Ontario or the OPA, such as the OPA Feed-in Tariff (FIT) Program and micro-FIT Program and activities related to the price of electricity or general economic activity; and

iii. that lost revenues that result from Province-Wide Distributor CDM Programs or Local Distributor CDM Programs should not act as a disincentive to Distributors in meeting their CDM Requirement.

4. The Board shall establish a DSM policy framework ("DSM Framework") for natural gas distributors whose rates are regulated by the Board ("Gas Distributors"). In establishing the DSM Framework, the Board shall have regard to the following objectives of the government in addition to such other factors as the Board considers appropriate:

   i. that the DSM Framework shall span a period of six years, commencing on January 1, 2015, and shall include a mid-term review to align with the mid-term review of the Conservation First Framework;

   ii. that the DSM Framework shall enable the achievement of all cost-effective DSM and more closely align DSM efforts with CDM efforts, as far as is appropriate and reasonable having regard to the respective characteristics of the natural gas and electricity sectors;

   iii. that Gas Distributors shall, where appropriate, coordinate and integrate DSM programs with Province-Wide Distributor CDM Programs and Local Distributor CDM Programs to achieve efficiencies and convenient integrated programs for electricity and natural gas customers;

   iv. that Gas Distributors shall, where appropriate, coordinate and integrate low-income DSM Programs with low-income Province-Wide Distributor CDM Programs or Local Distributor CDM Programs;

   v. that the Board shall annually review and publish the verified or audited results of each Gas Distributor's DSM programs;

   vi. that an achievable potential study for natural gas efficiency in Ontario should be conducted every three-years, with the first study completed by June 1 2016, to inform natural gas efficiency planning and programs. The achievable potential study should, as far as is appropriate and reasonable having regard to the respective characteristics of the natural gas and electricity sectors, be coordinated with the OPA with regard to the OPA's requirement to conduct an electricity efficiency achievable potential study every three-years;

vii. that DSM shall be considered to be inclusive of activities aimed at reducing natural gas consumption, including financial incentive programs and education programs; and

viii. that lost revenues resulting from DSM programs should not act as a disincentive to Gas Distributors in undertaking DSM activities.

5. By January 1, 2015, the Board shall have considered and taken such steps as considered appropriate by the Board towards implementing the government's policy of putting conservation first in Distributor and Gas Distributor infrastructure planning processes at the regional and local levels, where cost-effective and consistent with maintaining appropriate levels of reliability.

6. Nothing in this Directive shall be construed as directing the manner in which the Board determines, under the *Ontario Energy Board Act, 1998*, rates for Gas Distributors or for Distributors, including in relation to applications regarding regional or local electricity demand response initiatives or infrastructure deferral investments.

Ministry of Energy

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Ontario

OCT 2 3 2014

Mr. Colin Andersen
Chief Executive Officer
Ontario Power Authority
1600–120 Adelaide Street West
Toronto ON M5H 1T1

Dear Mr. Andersen:

RE: Amending March 31, 2014 Direction Regarding 2015-2020 Conservation First Framework

I write in my capacity as the Minister of Energy in order to exercise the statutory power of ministerial direction I have in respect of the Ontario Power Authority (OPA) under the *Electricity Act, 1998,* as amended (Act).

Background

In *Achieving Balance: Ontario's Long-Term Energy Plan* (LTEP 2013), released on December 2, 2013, the Government established a provincial conservation and demand management (CDM) target of 30 terawatt hours (TWh) in 2032. To assist the Government in achieving this target, LTEP 2013 also committed to establishing a new six-year Conservation First Framework beginning in January 2015, replacing the one that is currently winding down.

On March 31, 2014, I directed the OPA to coordinate, support and fund the delivery of CDM programs through licensed electricity distributors ("Distributors") to achieve a total of 7 TWh of reductions in electricity consumption between January 1, 2015 and December 31, 2020, in accordance with specified guiding principles and requirements ("March 2014 Direction").

In the March 2014 Direction, I directed the OPA, in consultation with Distributors, to develop a cost recovery and performance incentive mechanism for Distributors for making Province-Wide Distributor CDM Programs and/or Local Distributor CDM programs available to customers in their service areas. I also directed the OPA to ensure that there is a positive benefit-cost analysis of each CDM Plan and each Province-Wide CDM Program and Local Distributor CDM Program utilizing the OPA's Total Resource Cost Test and the Program Administrator Cost Test found in the OPA's Cost-Effectiveness Guide, dated October 15, 2010, which may be updated by the OPA from time to time ("OPA Cost-Effectiveness Tests").

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On April 24, 2014, the government released its Five-Point Small Business Energy Savings Plan to help mitigate electricity rate increases for small businesses by offering enhanced conservation programs. In partnership with Distributors and key agencies, the plan will help small businesses conserve energy, manage costs and save money. A key element of the plan is promoting the use of energy managers. Energy managers play an important role in encouraging customers to make use of conservation programs and implement conservation measures.

I now wish to give further direction to the OPA with respect to performance incentives under the full cost recovery mechanism, OPA Cost-Effectiveness Tests and the procurement of energy managers.

Direction

Therefore, pursuant to my authority under section 25.32 of the Act, I hereby direct the OPA as follows:

1. Notwithstanding section 1.6(i) of the March 2014 Direction, which provides that incentives shall begin to accrue once a Distributor achieves 100 per cent of the portion of its Distributor CDM Target allocated to the full cost recovery mechanism, the OPA shall make an additional incentive mechanism available to Distributors at the formal mid-term review contemplated in section 6.1 of the March 2014 Direction (by June 1, 2018), subject to the following terms:

   (i) A Distributor shall be eligible for a mid-term incentive if, by December 31, 2017, that Distributor has achieved a minimum of 50 per cent of the lesser of either:

      a. its Distributor CDM Target allocated to the full cost recovery mechanism; or

      b. any amended Distributor CDM Target that is proposed by the OPA pursuant to sections 6.1 and 6.2 of the March 2014 Direction that is not allocated to the pay for performance mechanism set out in section 1.6(ii) of the March 2014 Direction;

   (ii) Notwithstanding section 1(i) of this Direction, where a Distributor participates in a joint CDM Plan, the Distributor shall only be eligible for a mid-term incentive if, by December 31, 2017, the Distributors participating in such joint CDM Plan have collectively achieved a minimum of 50 per cent of the lesser of either:

      a. their aggregated Distributor CDM Targets allocated to the full cost recovery mechanism; or
      b. the aggregate of any amended Distributor CDM Targets that are proposed by the OPA pursuant to sections 6.1 and 6.2 of the March 2014 Direction, that are not allocated to the pay for performance mechanism set out in section 1.6(ii) of the March 2014 Direction;

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(iii) For the purpose of calculating whether a Distributor has achieved a minimum of 50 percent of its Distributor CDM Target or proposed amended CDM target, the OPA shall consider only those electricity savings achieved by December 31, 2017 that are expected to persist to at least December 31, 2020;

(iv) Any performance incentives which accrue once the Distributor achieves 100 per cent of its Distributor CDM Target allocated to the full cost recovery mechanism will be reduced by the amount of any performance incentive a Distributor receives at the mid-term review; and

(v) For greater certainty, nothing in this section amends the requirement set out on the March 2014 Direction that Distributor CDM programs will result in the full achievement of 7 TWh of electricity savings.

2. In ensuring that there is a positive benefit-cost analysis of each Distributor CDM Plan and each Province–Wide CDM Program and Local Distributor CDM Program utilizing the OPA's Total Resource Cost Test and the Program Administrator Cost Test found in the OPA's Cost-Effectiveness Guide, as contemplated in section 3.5(v) of the March 2014 Direction, the OPA shall require that the benefits calculated for the Total Resource Cost Test include a 15 per cent adder to account for the non-energy benefits associated with Province-Wide CDM Programs and Local Distributor CDM Programs, such as environmental, economic and social benefits. The value attributed to non-energy benefits shall be subject to review at the formal mid-term review provided in section 6.1 of the March 2014 Direction.

3. The OPA shall procure and coordinate the cost-effective services of energy managers to ensure their sufficient availability to target small business, commercial and institutional customers across the province. For certainty, this shall not restrict Distributors from developing complementary Province-Wide Distributor CDM Programs and Local Distributor CDM Programs to procure and coordinate the cost-effective services of energy managers within their licensed service areas.

General

4. This direction supplements and amends previous directions to the extent that such previous directions are inconsistent with the provisions of this direction. All other terms of any previous direction remain in full force and effect.

This direction takes effect on the date it is issued.

Sincerely,

Bob Chiarelli
Minister

c. James D. Hinds, Chair, Ontario Power Authority
Serge Imbrogno, Deputy Minister, Ministry of Energy
Halyna Perun, Director, Legal Services Branch, Ministries of Energy, Economic Development, Employment and Infrastructure, and Research and Innovation

Ministry of Energy

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RECEIVED

FEB 09 2014

CHAIR
ONTARIO ENERGY BOARD

Ontario

FEB - 4 2015

Ms Rosemarie T. Leclair
Chair & Chief Executive Officer
Ontario Energy Board
PO Box 2319
2300 Yonge Street
Toronto ON M4P 1E4

Dear Ms Leclair:

Re: Natural Gas Demand Side Management (DSM) Framework

I am pleased that the Ontario Energy Board (OEB) has released its final DSM Framework (2015-2020) in support of the government's Conservation First policy. Conservation is the cleanest and most cost-effective energy resource and it offers consumers a way to reduce their energy bills while contributing to a sustainable future.

I am particularly pleased that natural gas distributors will be expected to ensure that DSM is considered in infrastructure planning at the regional and local levels, consistent with the government's March 26, 2014 Directive to the OEB, and that a 15 per cent non-energy benefit adder will be applied to the benefit side of the Total Resource Cost Test in recognition of the environmental, economic and social benefits of DSM.

I note that as part of the expectation that natural gas distributors consider DSM in infrastructure planning, each distributor will be studying the potential role of DSM in reducing or deferring infrastructure investments in future system planning efforts. I expect that the natural gas distributors will work with stakeholders, including environmental organizations, to help inform the approach for these studies. I understand that they plan to initiate this work in the near future and complete the studies as soon as possible and no later than in time to inform the mid-term review of the DSM Framework.

The March 26, 2014 directive also requires an achievable potential study for natural gas efficiency in Ontario be conducted every three years with the first study completed by June 1, 2016. Building on the principle of the non-energy benefit adder, I request that the Board consider, in that study, how such potential DSM benefits as carbon reduction and natural gas price suppression may be used to screen prospective DSM programs and inform future budgets.

.../cont'd

I look forward to the OEB's continued support in implementing the government's Conservation First policy.

Sincerely,

Bob Chiarelli
Minister

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BY E-MAIL AND WEB POSTING

April 10, 2014

To: All Rate-regulated Natural Gas Distributors
All Licensed Electricity Distributors
All Members of Enbridge Gas Distribution Inc.'s and Union Gas Limited's DSM Consultative Groups

Re: Consultation Process for Developing a New Demand Side Management Framework for Natural Gas Distributors
EB-2014-0134

This letter outlines the consultation process by which the Board will develop a new Demand Side Management (DSM) Framework for rate-regulated natural gas distributors for the period January 2015 to December 2020. It also provides information on the next steps the Board will take to support the conservation and demand management (CDM) activities of licensed electricity distributors for the same period.

Background

The DSM Guidelines for natural gas distributors, issued by the Board on June 30, 2011, provides for a three-year term ending December 31, 2014. As the current DSM term is nearing its conclusion, the Board is initiating a consultation process to review the current DSM Guidelines and develop a new DSM Framework to be used for the development of the next generation of DSM plans.

On March 31, 2014, the Minister of Energy issued a Directive to the Board (the "DSM/CDM Directive") that among other things requires the Board to establish a DSM policy framework and to do so having regard to the following Government objectives:

- That the DSM Framework shall span a period of six years, commencing on January 1, 2015, and shall include a mid-term review to align with the mid-term review of the Conservation First Framework;

- That the DSM Framework shall enable the achievement of all cost-effective DSM and more closely align DSM efforts with CDM efforts, as far as is appropriate and reasonable having regard to the respective characteristics of the natural gas and electricity sectors;

- That Gas Distributors shall, where appropriate, coordinate and integrate DSM programs with Province-Wide Distributor CDM Programs and Local Distributor CDM Programs to achieve efficiencies and convenient integrated programs for electricity and natural gas customers;

- That Gas Distributors shall, where appropriate, coordinate and integrate low-income DSM Programs with low-income Province-Wide Distributor CDM Programs or Local Distributor CDM Programs;

- That the Board shall annually review and publish the verified or audited results of each Gas Distributor's DSM programs;

- That an achievable potential study for natural gas efficiency in Ontario should be conducted every three-years, with the first study completed by June 1, 2016, to inform natural gas efficiency planning and programs. The achievable potential study should, as far as is appropriate and reasonable having regard to the respective characteristics of the natural gas and electricity sectors, be coordinated with the OPA with regard to the OPA's requirement to conduct an electricity efficiency achievable potential study every three-years;

- That DSM shall be considered to be inclusive of activities aimed at reducing natural gas consumption, including financial incentive programs and education programs; and

- That lost revenues resulting from DSM Programs should not act as a disincentive to Gas Distributors in undertaking DSM activities.

Also, the DSM/CDM Directive states that by January 1, 2015, the Board shall have considered and taken such steps as considered appropriate by the Board towards implementing the government's policy of putting conservation first in Distributor and Gas Distributor infrastructure planning processes at the regional and local levels, where cost-effective and consistent with maintaining appropriate levels of reliability.

DSM Framework for Natural Gas Distributors

Given the evolving policy environment, the Board intends to undertake a comprehensive review of the framework governing gas distributors' DSM activities. In developing the new DSM Framework, the Board will consult broadly with stakeholders.

David I. Poch Barrister tel. (613) 264-0055 fax (613) 264-2878

30 July 2014

Ontario Energy Board
2300 Yonge St., 27th Floor
Toronto, ON
M4P 1E4

Attn: Ms. Rosemarie T. Leclair, Chair

By e-mail

Dear Ms. Leclair:

Re: EB-2014-0134 Consultation to develop a new DSM Framework for natural gas distributors for the period 2015 to 2020.

On April 17th I wrote to you on behalf of the GEC[1] concerning the process going forward for the Board's consideration of the matters being considered by the DSM working group. As you will recall, despite GEC's central role in the evolution of the current DSM framework it was not invited to participate in that committee. We have had no response to our letter.

We now understand that Board Staff will be proposing to the Board a cap on DSM budgets and several significant changes to the framework. These are fundamental issues deserving of proper consultation. For example, Staff is proposing a budget cap that is proportional to electricity CDM budgets based on relative revenue requirements. In our view such a cap is neither in compliance with the Minister's explicit direction to the Board to base the framework on achievement of *all cost-effective conservation*, nor is it based on an appropriate comparator with the electricity sector for how fast the ramp up should occur.

DSM and CDM are about efficient use of energy and reducing environmental impacts. If a comparator is appropriate, surely it must consider the relative use of energy by fuel type and the contribution to climate change. According to Board Staff, Ontario's electric CDM budget is $367 million per year for an energy source that supplies just 19% of our energy needs, whereas natural gas provides Ontario with 35% of its energy requirements (and an even higher relative

[1] The Green Energy Coalition (GEC) represents over 125,000 Ontario residents who are members or supporters of its member organizations: the David Suzuki Foundation, Greenpeace Canada, Sierra Club Canada Foundation and WWF-Canada. All of the GEC's member groups are charitable or non-profit organizations active on environmental and energy policy matters.

1649 Old Brooke Road, Maberly, Ontario K0H 2B0 e-mail: dpoch@eelaw.ca

contribution to GHG emissions)[2]. A ramp up to a proportional DSM budget over the six year period would be to $675 million per year, more than six times higher then what Board Staff is proposing. Board Staff's proposal is far too slow, though ramping up to $675m/yr. over six years may not be the right answer either. In GEC's view the appropriate benchmark is how fast and how far the top utilities have gone in achieving all cost-effective conservation, not some arbitrary comparison of revenue. In that regard a recent paper looking at Ontario's DSM situation offered the following observations[3]:

> Consider these four jurisdictions: two cold climate jurisdictions currently required to pursue all cost-effective gas efficiency resources -- Massachusetts and Rhode Island – and two others – Vermont and Minnesota – with at least comparable energy savings goals. As Table 1 shows, these four jurisdictions have annual DSM budgets that range from 3½ to 13 times (average of 8 times) greater than the current Ontario utility DSM budgets on a gas sales normalized basis. Put another way, if the Ontario gas utilities DSM budgets were to increase to levels comparable to those of leading jurisdictions, they would be at least $100 million per year per utility – at least $200 million for the province – and potentially several times that amount.
>
> …Some period of ramp up would be necessary to ensure that there is sufficient time to develop new and more aggressive programs, and to increase utility and private sector delivery capability in a reasonably efficient and effective manner. The experience of the Massachusetts gas utilities may be instructive in this regard. As Figure 1 below demonstrates, Massachusetts budgeted only $38 million for gas DSM in 2009, the year that a new legislative requirement to acquire all cost-effective efficiency went into effect. Spending then more than doubled the following year and continued to increase fairly linearly until 2013, at which point increases levelled off. In other words, the state ramped up to acquiring all cost-effective efficiency – with a nearly five-fold increase in budget – over the course of about 4 years.

In contrast Board Staff are proposing a 6 year budget ramp up to less than twice current levels. This is but one example of the complex and contentious issues at play. Others include the role of intervenors in audit and technical oversight. These are highly arcane matters where experienced intervenors such as GEC have routinely found significant problems that the auditors have missed and as a result we have saved ratepayers millions. We are greatly concerned that an inadequate process can lead to inadequate results.

We understand that Board Staff has indicated that the next step will be a Board proposal rather than a staff proposal.

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[2] Environmental Commissioner of Ontario, Restoring Balance – Results: Annual Energy Conservation Progress Report -2011 (Volume Two), page 58.

[3] We refer the Board to the papers provided by Toronto Atmospheric Fund that canvass this issue and others and that were authored by Mr. Chris Neme, a DSM expert that GEC has relied upon in numerous cases and who has earned widespread respect in the intervenor community: http://www.towerwise.ca/ontarios-natural-gas-conservation-framework/.

In our earlier correspondence we noted the following:

> Given the Board's pre-emptive determination of the DSM budget issue prior to the completion of the last DSM framework consultation, we are concerned that this first stage of consultation could freeze out a fair and meaningful consideration of alternatives in subsequent phases. While as a matter of law a proposal for comment or the issuance of a Board guideline does not bind the Board, the reality is that such pronouncements often amount to a de facto determination. Accordingly, we ask the Board to avoid formally or impliedly endorsing any conclusions or narrowing of options prior to non-working group members being offered the opportunity to participate and bring forward expert evidence.

We ask the Board to ensure that there is a suitable consultation process, open to all intervenors before the Board takes a preliminary position.

Sincerely,

David Poch
Cc: Lynne Anderson, Vice-President, Applications

EB-2014-0134

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch.B, as amended;

AND IN THE MATTER OF a consultation by the Ontario Energy Board on the draft DSM Framework and Guidelines for gas utilities for 2015-2020

GEC Comments on the OEB Draft DSM Framework

Contents

Introduction - collaborative efforts informing these comments

GEC has had the benefit of discussions with both companies and most of the intervenor groups that are active on DSM issues. While time did not allow us to develop a common written submission, the Board will see from the various submissions that there is a significant degree of consensus on several issues. We trust this will assist the Board in its deliberations.

Targets

1) Is a total reduction equal to 5% of average annual gas sales from 2011 to 2013, attributable to DSM programs, a reasonable amount for the gas utilities to be expected to achieve in 2020 (consisting of savings in 2020 and savings from 2015 to 2019 persisting in 2020)?

In addressing this question GEC starts from the premise that the Minister's Directive calls for ***all cost effective conservation.*** The 5% value for savings persisting in 2020 that is suggested is simply not in conformity with this clear mandate from the Minister. The Board appears to have based this value on a six year 0.8% per year target which simply reflects past achievements in Ontario, not achievable potential. Frankly, we cannot comprehend how an average level of savings no greater than that already being achieved can be seen as serving the Directive of achieving all cost-effective DSM.

In the TAF paper entitled *Are Gas Energy Efficiency Programs Worth the Money?*, the value of gas DSM is succinctly illustrated:

> The simplest way to look at the cost of utility-run efficiency programs is to compare how much the utility spent per unit of energy saved, over the life of the savings (recognizing that many efficiency measures, such as insulating a home, will save gas for many years). The Ontario results for 2012 are as follows:
>
> - Enbridge Gas' energy efficiency programs cost an average of just $0.06 per m3 of gas saved.
> - Union Gas' programs cost even less – an average of just $0.03 per m3 of gas saved – mainly because it has more large industrial customers for which efficiency savings are usually less expensive.
> - The average customer currently pays on the order of $0.30 to $0.35 per m3 consumed, even after one excludes the fixed monthly charge.

DSM	Gas
3¢ - 6¢ per m^3	30¢ - 35¢ per m^3

To forego such dramatic benefit without fully understanding the trade-offs is not good public policy. Accordingly, we view the 5% target (even if simply a placeholder) as problematic for several reasons:

- Past achievements were prior to the enhanced mandate contained in the Minister's Directive to target all cost-effective conservation and are thus no indication of what is achievable going forward.
- The Board has acknowledged we do not yet know what the conservation potential is. While old or even currently underway conservation potential studies provide some guidance, they were done with inadequate valuation of efficiency (see below under screening), no 'conservation first' mandate, and even so found significantly greater potential than the Board's potential target. See TAF Paper #1.
- The Board has relied upon the Concentric review to inform its starting point and this has led to three critical methodological failings. First, it mixes utilities that have a mandate to achieve 'all cost-effective' with those that don't. Second, it fails to consider projections of where these leading utilities expect to be over the next 6 years -- which is the task before the Board in Ontario. Third, Concentric did not limit comparisons to jurisdictions with comparably cold weather. As discussed below, utilities in leading jurisdictions that share Ontario's weather patterns and that have a similar 'all cost-effective conservation' mandate are targeting much higher levels of savings in 2015 let alone six years hence.
- Because the budget will be informed by the targets, a poorly informed target will become a self-fulfilling prophesy as budgets will constrain results.

- The 0.8% does not adjust for the differing customer composition between the comparator utilities in other jurisdictions and Ontario's LDCs (nor as between Enbridge and Union).
- Because of the different customer makeup of Enbridge and Union, a single indicative value is not appropriate.

As discussed by Mr. Neme in the TAF issue paper: *Savings Goal and Budget Setting,* presently there are only two other "cold climate jurisdictions" in North America that have a mandate to pursue all cost-effective gas DSM: Massachusetts and Rhode Island. Both of those jurisdictions are proposing to capture savings equal to about 1.1% of total (all sector) sales in their current plans for 2015. Though not operating under an "all cost-effective" mandate, gas utilities in Vermont (1.1% in 2013) and Minnesota (1.3% in 2015 plans) have comparable savings levels (again, in aggregate across all sectors).

In both Massachusetts and Rhode Island, approximately 50% of gas sales are to residential customers; only about 20% is to industrial customers. Gas sales in Ontario are more heavily weighted towards the industrial sector. Thus, one would expect savings potential in Ontario to be higher than in Massachusetts and Rhode Island, at least in the short and medium term.

In summary, there is simply no basis to assume that 5% is indicative of achievable potential six years from today. The 2015 targeted levels of leading cold climate jurisdictions with a comparable mandate would suggest a target exceeding 6.6%. (Massachusetts, Vermont and Minnesota all have similarly cold climates and have all been doing DSM for a long time at least as aggressively as Ontario and are reasonable comparators). Adjusting that to reflect the higher industrial proportion of Ontario customers would raise the appropriate value further. Ramping up the value over 6 years to reflect the ever expanding range of conservation technologies and experience as well as new approaches such as performance-based conservation programs for large buildings would add more still.

Further a ramp up to 'all cost-effective' can be expected to take much of the initial three year period, further complicating the analysis of a suitable 2020 level.

Given that there is no up to date data available at this time to set targets that reflect a rigorous analysis of achievable potential or of acceptable rate impacts, (see discussion below) if the Board believes that a placeholder target is needed for 2020, it should be subject to adjustment once updated potential studies are available in three years as required by the Directive.

Budgets

1) Should the Board provide a budget guideline that sets out the expected maximum DSM budgets?

GEC does not support the issuance of a budget guideline at this time because such a guideline will conflict with the Minister's Directive and because there is a lack of adequate data and analysis available.

Given the Directive to acquire all cost-effective DSM it is necessary to determine what is cost-effectively achievable prior to setting a budget. Failure to do so will mean an arbitrary budget that risks constraining achievement of the mandate.

It is particularly notable that the Minister's Directive does not include reference to a need to constrain rate impacts. While the Board will of course have regard to rate impacts in accord with its statutory objectives and as a reasonable consideration, GEC submits that any compromising of the direction to achieve all cost-effective DSM due to a concern about rate impact must be based on an analysis of what rate impact would be undue given the bill reducing benefits and societal benefits of DSM. The Board should require such an analysis be conducted prior to setting a budget.[3]

2) If the Board decides to establish a budget guideline, is 6% of 2013 distribution revenue appropriate (plus applicable shareholder incentives)?

The Board cites the Concentric analysis of budgets in other jurisdictions in support of this suggestion. However, that analysis and its application suffers from two problems. First, it fails

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score). However, this change may best be considered as part of the development of the initial plan by the LDC's in cooperation with intervenors.

[3] For examples of the data and considerations appropriate see:

http://aceee.org/files/pdf/conferences/eer/2013/5C-Woolf.pdf

https://www4.eere.energy.gov/seeaction/system/files/documents/ratepayer_efficiency_billimpacts.pdf to project budgets forward for 6 years to adjust for inflation and for the growth in programs that the comparator jurisdictions are experiencing. Second, it inappropriately focusses on DSM spending per dollar of distribution revenue rather than DSM spending per cubic metre of gas sales. DSM is first and foremost about reducing gas consumption and costs. Leading small jurisdictions like Vermont will necessarily have relatively higher distribution costs per cubic meter of gas delivered. They will therefore require a lower ratio of DSM budget to distribution costs. The proper comparison is DSM spending/m3 of gas sales. As can be seen in the TAF paper, comparable jurisdictions are spending 4 to 12 times as much per unit of gas sales as Ontario currently does.

As discussed above, budget should flow from an analysis of achievable potential and required program effort. And as discussed below, any curtailment of the optimal budget to reflect concern about rate impacts must be based on a more rigorous analysis of the level and cause of the rate impacts versus the breadth and depth of the savings and the pattern in which they are enjoyed amongst the customers.

3) What information, other than what is listed above, should the utilities/Board consider when developing the long-term budgets?

As discussed above, DSM spending/m3 gas sales of leading jurisdictions is a more suitable comparator.

Efficient ramp up capability and concern about rate impacts are the key potential constraining factors that can reduce the appropriate level of budget below that required to achieve all cost-effective conservation and both should be analysed before a cap is determined.

As to rate impacts, typically it is not the budget that causes them. As Mr. Neme discussed in the TAF paper on this topic, there are a two aspects of DSM that cause upward pressure on rates - DSM spending and lost revenues. On the other hand, there are several aspects that cause downward pressure on rates - reduced utility T&D/capital investments, commodity price suppression effects of lower demand, and reduced utility credit and collection costs, none of which have been analyzed or counted in Ontario decision-making to date. In other words, rate impacts cannot be associated with a particular budget. Indeed, two different DSM portfolios with the same budget can have very different rate impacts depending on what the DSM produces in terms of both downward pressure on rates and lost revenues. In addition, the magnitude of rate impacts that would be acceptable should depend on the magnitude of

- The largest programs accounting for up to 70% of annual savings should have an impact evaluation, as well as (or including) a net-to-gross evaluation. This will ensure confidence in savings estimation.

Inputs

Please see our comments on the appropriate role of Board Staff and the intervenor committees, above. GEC submits that the TEC is well positioned to retain and instruct experts in regard to measure input studies.

Screening

GEC favours a Societal Cost Test (SCT) in keeping with the public policies driving DSM. In the alternative, if the TRC test is to be utilized, GEC is concerned that the test is current being narrowly applied in Ontario, recognizing all costs but only some benefits. We submit that the framework should call upon the utilities to develop placeholder values and conduct further analysis on a range of screening parameters. In particular:

- As the Board has noted the utilities must consider the avoidable costs of distribution and transmission pipelines. Placeholder values could be considered for use until studies provide a more detailed analysis.
- Ontario has a policy to reduce GHGs by 15% by 2020. The Minister's Directive indicates part of the rationale for Conservation First is to support Ontario's GHG goals. In the foreseeable future carbon tax or cap and trade costs will likely emerge. Accordingly, given the long term nature of avoided costs, a carbon adder should be included in avoided costs. Carbon values from a survey of 22 utility integrated resource plans found that most range from $20 to $40/tonne. See TAF Paper #4.
- The commodity price-reducing effect of DSM demand reduction should be included. The Board should indicate this in its framework policy and refer it to Board Staff and the TEC to complete a study within a year to add to avoided costs. Again, a placeholder value could be considered based on the work done in other jurisdictions pending study results.

- DSM insulates Ontario ratepayers against the risk of fluctuating gas prices. The Board should authorize the use of a 10% adder, as is the case in Vermont to recognize the risk mitigation benefits of efficiency.
- Non-energy benefits to participants should be included. The TRC should capture the impacts to the utility system plus the impacts on participants. Right now, it only captures the cost impacts to participants and ignores all non-energy benefits to participants. A proxy adder can be used until more study can be conducted. Consistent with the recent decision in Vermont, we would recommend an interim value of 15% pending further study.

Deferral Accounts

No specific concerns.

Integration with CDM

No specific concerns.

Future Infrastructure Planning Activities

The Minister's Directive includes a requirement that by Jan 1, 2015 steps be taken to implement the conservation first policy in gas distributor regional and local planning processes. However the Board's draft requires only that the utilities study the question of how to carry out IRP over the next 3 years and then make proposals. Instead the Board should require that:

- The average avoided costs of supply side infrastructure should be incorporated into avoided costs for 2015;
- The utilities should annually develop/update a 10 year forecast of capital investment requirements; identifying all that are at least in part a function of load growth;
- Effective immediately, all facilities approval proposals of more than $5 million from the LDCs should include an analysis of cost-effective DSM options as an alternative to supply

side options. This would be consistent with the practice in other jurisdictions doing LIRP. (See US Experience with Efficiency As a Transmission and Distribution System Resource, Neme et al.) The analysis should include the additional avoidable costs in the region to be served by pipeline expansions and targeted DSM programs should be proposed and implemented which use both system-wide and local avoided costs and employ more intensive marketing.

- In addition, GEC supports offering the LDCs specific shareholder incentives for successful DSM efforts that reduce or eliminate supply side investments. These should be designed at the time of facility cases and be proportionate to the savings produced.

Stakeholder Consultation

Broad consultation with stakeholders is of course to be encouraged, however, it is not a substitute for the transparency, independent oversight, enhanced input and broad experience that the committee processes can offer. Nor does stakeholder consultation significantly reduce the need for contested proceedings in the way that meaningful, empowered committee processes can.

Comments on this process

GEC is concerned that the consultation process that the Board is employing to develop the DSM framework is not adequate for the task at hand. As we have noted above, the key issues are best considered in light of suitable data and analyses that are not presently available nor tested. The lack of a mechanism for parties to test each other's evidence and positions diminishes the value of the input that is available to the Board. The limitation on the cost award available has limited the resources that intervenors can bring to the exercise. While we have endeavoured to mitigate these limitations by way of our discussions with the companies and other intervenors, we remain concerned that should the Board proceed to issue specific guidance on targets and budgets based on the proceedings thus far it will be doing so without a proper evidentiary basis. We submit that these procedural and information shortcomings can best be cured by selecting options that require the companies to develop key parameters in

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BY EMAIL AND WEB POSTING

August 21, 2015

To: **All Natural Gas Distributors**
All Participants in the Consultation Process EB-2014-0134
Other Stakeholders

Re: **2015-2020 Demand Side Management Evaluation Process of Program Results**
EB-2015-0245

This letter establishes the OEB's process to evaluate the results of Natural Gas Demand Side Management (DSM) programs from 2015 to 2020.

Background

As outlined in Section 7 of the OEB's Report on DSM issued December 22, 2014, the OEB will be taking a central role in the evaluation process of DSM program results. DSM programs will be evaluated on an annual basis, with results issued by the OEB to be used by the gas utilities when they file applications for recovery of amounts related to DSM activities.

DSM Evaluation Governance

The OEB will rely on the DSM evaluation governance structure outlined below. The evaluation governance structure describes the general role of the main parties involved in the evaluation process. The evaluation governance structure is expected to be fully implemented following the OEB's selection of an Evaluation Contractor.

OEB's DSM Evaluation Governance Structure	
Party	**Role**
OEB	The OEB is responsible for coordinating and overseeing the evaluation and audit process, including selecting a third party Evaluation Contractor and publishing the final evaluation results on an annual basis.
Evaluation Contractor (EC)	The Evaluation Contractor will carry out the evaluation and audit processes of all DSM programs.
Natural Gas Utilities	The natural gas utilities are responsible for developing an initial evaluation plan that will inform the evaluation of programs, filing an annual draft evaluation report and providing program data and coordination support to the Evaluation Contractor and OEB staff, as requested.
Evaluation Advisory Committee (EAC)	An Evaluation Advisory Committee (EAC) will be formed to provide input and advice to the OEB on the evaluation and audit of DSM results. The EAC will consist of representatives from non-utility stakeholders, independent experts, staff from the Independent Electricity System Operator (IESO), and observers from the Environmental Commissioner of Ontario and the Ministry of Energy, all working with OEB staff.

Evaluation Approach

The OEB will retain a third party Evaluation Contractor to undertake DSM program evaluations and annual audits of program results.

The Evaluation Contractor will draft an Evaluation, Measurement & Verification (EM&V) Plan for the natural gas utilities' DSM programs for approval by the OEB. The EAC will provide advice and input on the development of the plan as required. The EM&V Plan will, at a minimum, address the following:

- Annual Evaluation and Audit of DSM results
- Annual update of input assumptions
- Multi-year DSM program impact assessments and evaluation studies

The OEB-approved EM&V plan is expected to span a period of three-years to coincide with the mid-term review of both the 2015 to 2020 Natural Gas DSM Framework and Electricity CDM Framework.

Annual Evaluation & Audit Process

Consistent with current evaluation practices, the Evaluation Contractor will be responsible for auditing each gas utility's annual DSM results based on the three-year OEB-approved EM&V plan. The detailed annual evaluation and audit process will be developed as part of the EM&V plan.

Updating Input Assumptions

The Evaluation Contractor will review and propose updates to the OEB related to data within the Technical Reference Manual (TRM) on an annual basis. This review of the TRM will include proposed updates to input assumptions to reflect the findings of the annual DSM evaluation and audit. This may require additional research in order to add any new technologies to the TRM and improve the current list of assumptions.

Best efforts will be made to align the natural gas DSM input assumptions list with the electricity CDM input assumption list, where appropriate. The OEB is of the view that having alignment on resource savings amounts related to both natural gas and electricity energy efficiency technologies will help enable a greater level of integrated and collaborative program design and delivery.

Multi-Year DSM Program Impact Assessments and Evaluations

The OEB will engage the Evaluation Contractor to conduct multi-year impact assessments and targeted evaluations of selected natural gas DSM programs on a periodic basis throughout the 2015 to 2020 DSM period.

Within the Evaluation Contractor's multi-year impact assessments, the Evaluation Contractor will be responsible for undertaking various studies which may include estimating natural gas savings, undertaking net-to-gross studies, investigating free ridership rates and spillover effects, examining the level of persisting natural gas savings from various programs and conducting other evaluation studies as required.

Transition Plan

The OEB recognizes that there is a current evaluation process underway, led by the natural gas utilities with support from three committees: the Technical Evaluation Committee (TEC), and two Audit Committees (one for each utility). The committees are comprised of natural gas utility staff, industry stakeholders and independent experts.

The current responsibilities of the TEC include the development of the Technical Reference Manual (TRM), the completion of a Commercial and Industrial Custom Project Net-to-Gross Study, a joint utility Boiler Baseline Study, and the initiation of a Persistence Study. This is important work that should continue at this time. The evaluation and audit of all natural gas DSM program results under the new 2015–2020 DSM Framework will follow the new process outlined in this letter. Once an Evaluation Contractor is retained by the OEB, OEB staff will work with the TEC on an appropriate plan to transition to the new framework on a go-forward basis. With the formation of an Evaluation Advisory Committee (EAC), as described below, an Audit Committee will no longer be required.

Formation of the Evaluation Advisory Committee

The Evaluation Advisory Committee (EAC) will provide input and advice as required throughout the DSM evaluation process. The EAC will be comprised of:

- Experts representing non-utility stakeholders, with demonstrated experience and expertise in the evaluation of DSM technologies and programs, natural gas energy efficiency technologies, multi-year impact assessments, net-to-gross studies, free ridership analysis and natural gas energy efficiency persistence analysis
- Expert(s) retained by the OEB
- Representatives from the IESO
- Representatives from each natural gas utility
- Representatives from the Ministry of Energy (MOE) and the Environmental Commissioner of Ontario (ECO), who will participate as observers

The OEB has recently selected a group of experts representing non-utility stakeholders to provide input and advice as part of the DSM Technical Working Group formed for the natural gas conservation potential study. As the technical expertise and experience required for both the DSM Technical Working Group and EAC are similar, the OEB has appointed the same individuals to represent non-utility stakeholders on the EAC as follows:

- Chris Neme, Energy Futures Group
- Jay Shepherd, Jay Shepherd Professional Corporation
- Marion Fraser, Fraser & Company

Due to a potential conflict, Ian Jarvis, who is a member of the DSM Technical Working Group, has not been included as a member of the EAC.

In reviewing nominations from non-utility stakeholders as part of the formation of the DSM Technical Working Group, the OEB considered the diversity of their expertise, their participation in similar OEB proceedings and working groups and their experience with the Ontario natural gas sector, as well as their ability to represent stakeholders. The selected candidates are expected to provide input and advice based on their experience and technical expertise and not to advocate position of parties they have represented before the OEB in various proceedings.

The OEB will determine the appointment of additional experts following the selection of an Evaluation Contractor.

Cost Awards

Cost awards will be available under Section 30 of the *Ontario Energy Board Act, 1998* to eligible persons in relation to their participation in the Evaluation Advisory Committee or other consultations during the course of the DSM evaluation process. Details will be provided at the appropriate time. Costs awarded will be recovered from all rate-regulated natural gas distributors based on their respective distribution revenues.

If you have any questions regarding this consultation process, please contact Josh Wasylyk at Josh.Wasylyk@OntarioEnergyBoard.ca or at 416-440-7723.

The OEB's toll free number is 1-888-632-6273.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

Green Energy Coalition

Undertaking of Mr Chernick

To Mr. O'Leary

Undertaking:

GEC to provide the number from quad to $10^9 m^3$ metres, the exchange rate or the conversion rate to Canadian dollars, and the inflation assumed.

Response:

The request is for the conversion from the DRIPE coefficient of $0.1502/MMBtu decrease in Henry Hub gas price for every quad decrease in annual gas consumption (in 2012 US dollars, from the 2014 AEO results), to \$0.00027/m^3 per $10^9 m^3$ saved (in 2015 Canadian dollars). The conversion factors are as follows:

- Inflation of 3.6% from US 2012 dollars to US 2015 dollars.
- Currency exchange rate of 1.26 Canadian dollars per US dollar.
- 28.2 m^3/MMBtu and 28.2 $10^9 m^3$/quad.

To convert from US to Canadian units, one can multiply 1.036 for inflation and 1.26 for the currency conversion, and dividing by 28.2 twice (once for the unit in which price is measured and once for the size of the reduction). These computations result in \$0.00025/m^3 per $10^9 m^3$ saved (in 2015 Canadian dollars); Mr. Chernick's original result of \$0.00027/m^3 resulted from an error in converting from MMBtu to Gj to m^3. The difference is not material for the purpose of Mr. Chernick's evidence in this proceeding.

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2015-0029**	**Union Gas Limited**
	EB-2015-0049	**Enbridge Gas Distribution Inc.**

VOLUME: **Technical Conference**

DATE: **August 17, 2015**

levels.

The second component is in terms of delivery, where you're looking at a market delivery price, or what's called basis, the difference between market prices at two different hubs, at a supply hub and a demand hub.

In that situation, when you're looking at that, you then have to be cognizant of a number of complications, including what demands are affecting price at that hub. And that can be demands downstream of the hub, and downstream can be difficult to define, depending upon the layout of the network, and also, in some cases upstream of the hub, between the supply and the hub you're looking at.

Now, in some situations -- and as you pointed out, storage can also affect that. So you can get a cold day and not have much of a price effect, because there's a lot of local storage or storage behind that hub downstream from it that's meeting the loads, and the market is looking ahead and seeing a warm front moving in, so there's -- nobody is bidding up the price thinking that we're going to be running short over the next week or two.

So in that situation, storage can be much more important than in the national markets, especially as in the analyzes that I've done in the past where I've looked at daily prices and daily throughput.

MR. QUINN: Thank you, I appreciate having additional detail, and we might be able to distinguish and drill down.

If we could open your evidence then at page 15 of your evidence, there is a figure 3, which I respect, based upon my interrogatory response, was withdrawn due to an error. I want to clarify the error, but then I have a follow-up question.

MR. CHERNICK: The error was that the heating degree days were just drawn from a wrong column of the table.

We downloaded a large amount of weather data and there was just a programming error in the spreadsheet, and it turned out not to be -- I forget exactly what the problem was, but it turned out not to be heating degree days for Toronto in February of 2015.

So I just -- I put this in as sort of an example of what you might see, and also giving me a chance to talk a little bit about the complications that storage and downstream weather patterns introduce, in terms of trying to model delivery DRIPE in this case, the basis DRIPE.

MR. QUINN: I think that that's sufficient. But because we had the prior conversation, for the benefit of the record, it was FRPO 3 wherein GEC says: “Figure 3 contains and error will be withdrawn."

I was just trying to get clarity on the error. I understand it's just a data error, Mr. Chernick, and that's sufficient.

MR. CHERNICK: Yes.

MR. QUINN: My question for you, more importantly, you said you wanted to demonstrate through that figure some of the challenges.

So could you, at a high-level, tell me what you believe that graph was trying to express in terms of DRIPE?

MR. CHERNICK: Yes, so I looked at these data and I was thinking about what would be involved in working out basis DRIPE for Dawn.

And I said, okay -- so assuming that this were actually the correct data, in the first half of February, you see a lot of ups and downs in temperature, but very little change in price. And certainly storage would contribute to that, as would the fact that you've got gas flowing through Dawn that flows through the Toronto area to other parts of Ontario that may be experiencing different weather, and on to Quebec and into new England and, to some extent, New York.

Therefore, you may have other weather, other than that in Toronto, affecting the gas demand.

MR. QUINN: There may be weather effects and because the data is flawed, I don't think either one of us want to rely on it for the purpose of this discussion.

But to take this to a high-level, is your premise that incremental demand will tend to trigger an increase in price, if supply is held constant?

MR. CHERNICK: Yes.

MR. QUINN: So if supply is constrained --

MR. CHERNICK: And by supply here, you mean the pipeline supply?

MR. QUINN: Pipeline supply and, in this case I was referring to pipeline supply -- thanks for the clarification. I won't get maybe to the pipeline -- well, let's say assuming the pipeline supply was held constant, and withdrawals from storage to sort of complete the picture and be able to detect the effect of end use demand on the basis.

MR. POCH: If I could interrupt? It might assist all parties to understand that Mr. Chernick and indeed, Mr. Neme, GEC, haven't suggested a particular value for this effect that should be taken as any -- in any sense definitive. The point in the evidence is just to say that this is an effect that is seen elsewhere, and may occur here and needs -- would need to be studied in the particular Ontario context.

So I don't -- if Mr. Quinn is worried that the .1 cent or something was intended to be the answer, I just want to assure him that's not where this is headed, and I believe that's not where Mr. Chernick intended to go.

It's just the question that -- the simple point is that this is a potential effect that needs to be studied in a proper analysis.

MR. QUINN: Thank you for the clarification, Mr. Poch. I guess what I'm concerned about, and what I'm going through with Mr. Chernick for the benefit of the record, is there are other effects beyond temperature that would have an impact on demand and in, this is case here, I was concerned that that graph tended to tell a different story than maybe was at play relative to heating degree day demand.

Based upon the withdrawal of the figure, and Mr. Chernick's lack of complete understanding of the balancing at Dawn which is accepted, I guess, Mr. Chernick, at a high-level, you have expressed that Dawn would be a point -- a market point where there could be a DRIPE effect.

Do you have any direct evidence of that DRIPE effect at Dawn, beyond what we've discussed to this point?

MR. CHERNICK: Okay. Well, this is in addition to the Continental supply level DRIPE. But in terms of basis DRIPE at Dawn I believe that generally basis from the supply areas to Dawn is higher in the winter months than in the summer months, which would be due to higher demand from somebody someplace, including Ontario, and so I think there is good reason to believe there is some in terms of what is that, how much is it per cubic metre.

I don't have a number in mind, and I think it's something that the Board should be encouraging the utilities and the parties to investigate further.

MR. QUINN: Okay. So maybe we can leave it at that. So it is a point for further investigation, but at this point you don't have the data nor the complete understanding of the Dawn market to be able to forecast a number?

MR. CHERNICK: That's correct. And I -- that was the point in my evidence from the beginning that I don't -- I haven't been able to do the analysis for this much more complicated hub. This is much more complicated than a sort of a pocket like New England or even the U.S. northeast.

MR. QUINN: That's where I was going to, because you made an analogy of TETCO. This is more complicated than

DR. HIGGIN: Okay, so that was the basis -- that's your professional opinion. That's why you're here. The question then is, just to clarify for everybody here: You and Mr. Neme are saying that on top of any TRC plus 15 percent adder, there would be an explicit adder for GHG based on this kind of policy context and these type of numbers. In other words, you are saying that it is over and beyond -- it is not included to the degree that you believe should be included in the TRC plus 15 percent. I guess you cannot speak for Mr. Neme.

MR. CHERNICK: Yes, I wouldn't call it an adder. The way that the Ontario government and the Board have used the adder, it's sort of a catch-all for things that can't be quantified.

DR. HIGGIN: Yes.

MR. CHERNICK: And right now we're guessing at what the carbon price will be, but it seems very likely there will be a carbon price. It is hard to see how you would get to the province's goals without a price for carbon emissions from natural gas. And that's an avoided cost, period. That's not what I would call an adder. It's really -- it's got to be part of the commodity price, or it's a -- it's a -- it is obviously not going to be part -- or it's not likely to be part of the price that's posted at Dawn, because it will be assessed after that level, but it's an avoided cost.

The 15 percent adder was supposed to take -- include a variety of environmental and social and economic benefits.

GEC Response to Enbridge Interrogatory #4

Question:

Reference: Exhibit L.GEC.1, page 18

Request:

a) Please provide a version of Table 3 on page 18 which includes a column for first year benefits only (as opposed to net present value of benefits).

b) Please also provide a column with first year costs.

Response:

a) and b) See table below. Note that some of the values in the original table in my evidence have been updated and/or corrected (see M.GEC.EP.1).

	Benefit	1st Year Benefits per Annual m³ Saved		1st Year Benefits as % of Avg Annual Budget (2016-2020)		NPV of Benefits per Annual m³ Saved		NPV of Benefits from Utilities' Proposed 2016-2020 DSM Plans (millions $)		NPV of Benefits as % of Avg Annual Budget (2016-2020)	
		Enbridge	Union	Enbridge	Union	Enbridge	Union	Enbridge	Union	Enbridge	Union
1	Avoided carbon regulation costs	$0.05	$0.05	6%	7%	$0.98	$0.98	$73.2	$73.9	101%	129%
2	Price suppression effects	$0.01	$0.01	1%	1%	$0.08	$0.08	$6.2	$6.3	9%	11%
3	Reduce purchase of most expensive gas	$0.01	$0.02	1%	2%	$0.10	$0.18	$7.2	$13.3	10%	23%
4	Avoided distribution system costs	$0.04	$0.02	4%	3%	$0.38	$0.24	$28.1	$18.2	39%	32%
	Total	**$0.11**	**$0.10**	**11%**	**13%**	**$1.54**	**$1.49**	**$114.7**	**$111.7**	**158%**	**195%**

The inclusion of a column showing first year costs could be confusing as there are no costs associated with each of the rows in Table 3. Thus, I have instead included columns showing the percent of average annual DSM budgets that the first year benefits would offset. That is consistent with how the table compares NPV of benefits to annual DSM budgets in the last two columns.

Note that concerns about the fact that benefits occur over time while DSM costs are felt in the year in which they occur could be addressed by amortizing (rather than expensing) DSM costs. Note also that DSM programs in 2014, 2013, 2012 and all other preceding years will be providing the same kinds of rate-reducing impacts, to participants and non-participants alike, in 2015, 2016 and other future years (i.e. for the lives of the efficiency measures installed).

Witness: Chris Neme

Revised Non-Participant Benefit Table

Benefit	1st Year Benefits per Annual m3 Saved[1]	Avg. 1st Year Benefits from Utilities' Proposed 2016-2020 DSM Plans (millions $)[6]	Avg. 1st Year Benefits for Residential Customers from Utilities' Proposed 2016-2020 DSM Plan (millions $)[7]	Typical Enbridge Residential Monthly Bill Impact in 2018 (2015 Dollars)[8]		
				As Filed	Including Possible Impacts	Difference (i.e. Illustrative Monthly Bill Savings)
Avoided carbon regulation costs[2]	$0.03	$2.16	$1.27			
Price suppression effects[3]	$0.00	$0.00	$0.00			
Reduce purchase of most expensive gas[4]	$0.01	$0.62	$0.37	**$2.13**	**$2.04**	**$0.09**
Avoided distribution system costs[5]	$0.01	$0.95	$0.56			
Total	**$0.05**	**$3.72**	**$2.20**			

1 Enbridge has taken the 1st year benefits per annual m3 saved of its DSM Plan, as calculated by Mr. Neme in Exhibit M.GEC.EGDI.4, and modified said values based on the rationale and calculations outlined for each benefit in the footnotes below.

2 Enbridge has reduced carbon costs by a factor of 0.54 to adjust costs from $20USD/ton to $15.22CAD/tonne as per 2018 Mean Price of 2018 Vintage Allowances in CA and QC. (as per GEC Compendium, Exhibit K1.2, p.20).

3 Enbridge does not believe the DRIPE's impact is significant enough to justify the complexity of determining its exact quantity. Mr. Chernick has noted that the Ontario gas market would be much more complicated to analyze than other markets such as New England or TETCO (Technical Conference Vol. 3, p.11-12).

4 Lacking a better figure, Enbridge has left unaltered GEC's estimate of the benefits to non-participants of avoided gas at marginal prices. This should not be interpreted as an endorsement of the figures provided by GEC.

5 As per page 18 of Exhibit L.GEC.1, Mr. Neme multiplied Enbridge's estimated avoided distribution costs by 4 to account for alterations to Enbridge's figures proposed by Mr. Chernick. Enbridge disagrees with this approach and has undone the multiplication of avoided distribution costs by 4. To account for admitted omissions in relevant portions of Enbridge's distribution costs as they were provided to Navigant for the purposes of their avoided distribution cost study, Enbridge has increased the benefits of avoided distribution system costs by 27%, proportionate to the increase in overall costs provided to Navigant as identified by Ms. Thompson on page 31 of Vol. 7 of the transcript (i.e. August 27, 2015).

6 Similar to Mr. Neme's analysis in Exhibit M.GEC.EGDI.4, Enbridge has multiplied the 1st year benefits per annual m3 saved by the average annual savings of its DSM Plan from 2016-2020, or 74.4 million m3. This shows the illustrative savings in rates accruing to all non-participants that take place in a single year.

7 74.4 million m3 are the average annual savings for Enbridge's entire DSM portfolio. This column shows only the benefits which would flow to Rate 1 residential customers. Allocation of these benefits to Rate 1 has been done in proportion to forecast Rate 1 allocation in 2018 of the Multi-Year DSM Plan, resulting in approximately 59% of benefits flowing to residential customers.

8 Using the illustrative benefits to Rate 1 residential non-participants Enbridge has compared the monthly bill impacts of its DSM Plan in 2018 to typical residential customers as filed, against a bill which includes or accounts for benefits to non-participants as estimated above. The difference between the two is 9 cents per month.

UNDERTAKING JT1.28

UNDERTAKING

Technical Conference TR, page 120

Enbridge to clarify the response to part (c), indicating that there was an error in the data given to Navigant, in terms of the reinforcement expenditures

RESPONSE

The reinforcement expenditures for Area 10 and Appendix B were inadvertently omitted from the information provided to Navigant. In addition, an equation error was made in the spreadsheet that was used by Enbridge to provide the reinforcement expenditures to Navigant that double counted the years from 2010 to 2012.

The reinforcement projects in Area 10 are those that were listed in GEC Interrogatory #57, filed as Exhibit I.T9.EGDI.GEC.57. The reinforcement projects in Appendix B are those that can be found in the response to GEC Interrogatory #56, Attachment 1, filed as Exhibit I.T9.EGDI.GEC.56.

It is estimated that the difference would be approximately $55M, which is an approximate 27% increase in the reinforcement expenditures that were used to calculate the original Avoided Distribution costs. The average overall impact of the $55M to the Avoided Distribution cost adder component of the Avoided Gas Costs over a 30 year period, results in a marginal increase of less than 1% in the Water Heating and Industrial load profiles, and an increase of less than 2% in the Space Heating and Space and Water Heating load profiles.

On average over a 30 year time period the Avoided Distribution costs account for approximately 1.5% - 5% (dependent on load profile) of the total Avoided Gas Costs.

As mentioned in the response to GEC Interrogatory #56 (c), Enbridge plans to re-file the Updated Avoided Distribution Costs Study, with the updated Avoided Gas Costs during the Input Assumption Update in Q4 2015. It should be noted that in preparation Enbridge intends to re-evaluate the purpose, need, and timing of the reinforcement projects given that it will be at least two years since the list included as Attachment 1 to GEC Interrogatory #56 was produced. The updated reinforcement forecast will be filed as part of the Updated Avoided Distribution Costs Study.

Witnesses: S. Mills
F. Oliver-Glasford
H. Thompson

GEC Response to Union Gas Interrogatory #1

Question:

Reference: L.GEC.1, Pages 9-10

Preamble: At section III.2, Mr. Neme states that "as Figure 1 shows, leading jurisdictions have already achieved savings levels (actuals for 2014) that are on the order of twice the average of what Enbridge and Union are forecasting to achieve…. "

Question: Union would like to better understand the information provided in Figure 1.

a) For Vermont, Massachusetts, Rhode Island and Minnesota please provide the following for each sector (Residential, Commercial and Industrial):
   i. 2014 Throughput
   ii. 2014 Number of customers per sector
   iii. 2012 Sales volumes per sector
   iv. 2012-2014 annual natural gas savings in cubic meters achieved through DSM programs
   v. 2012-2014 cumulative natural gas savings in cubic meters achieved through DSM programs
   vi. 2012-2014 Natural Gas DSM program budgets (per sector and total portfolio)

b) Please confirm the extent to which the U.S jurisdictions cited in Figure 1 have a Large Volume customer mix (i.e., number of customers, customer type, throughput volumes, sales, etc.) comparable to that of Union's franchise area.

Response:

a) See the table below. Note that Mr. Neme does not have the requested 2014 data on sales and customers; 2012 values are presented instead. Considerable effort was required to assemble just the 2014 program savings and spending by sector, so that is the only year provided. Lifetime energy savings were not readily available for Minnesota.

   Note that in the course of preparing this response, Mr. Neme discovered two errors in his previous estimation of savings as a percent of sales for Minnesota.[1] The correct value is 1.04% rather than the 1.34% previously estimated. However, it should be noted that the corrected value of 1.04% masks significant variability within the state, ranging from about 0.3% for one utility to between 1.2% and 1.3% for two of the three largest utilities. It should also be noted that these values are presented as savings from DSM eligible customers as a percent of total sales from all customers. Large customers in Minnesota

[1] The prefiled evidence will be corrected shortly.

Witness: Chris Neme

have an option to opt out of DSM programs and many have chosen to do so. Minnesota savings as a percent of sales to eligible customers is appreciably higher in some cases. For example, Excel Energy reported that its 2014 savings as a percent of eligible sales was close to 1.7%.

Some jurisdictions appear to allocate overhead and other costs not directly related to individual programs to a non-program budget category, whereas others appear to simply allocate all non-program costs to programs. That is why the budget row for "regulatory/other" is blank in some cases.

Finally, the blank in the low income budget and savings rows for Vermont Gas' does not mean that it does not address low income customers. Vermont Gas simply includes treatment of low income buildings in its Residential New Construction and Residential Retrofit programs. The spending on, and savings from, the low income participants in those programs are not separately reported, even though the programs have different strategies for the low income segments of the market. Also, it should be noted that as part of a long-standing Vermont state policy Vermont Gas customers pay a 0.5% gross receipts tax on their bills to pay for state administration of a low income home retrofit program. Neither the costs nor the savings from that program are included in the table.

		VT	MA	RI	MN
Number of Customers (2012)					
	Residential	39,917	1,411,717	228,487	1,364,174
	Commercial	5,535	119,742	21,442	125,831
	Industrial	38	6,027	56	1,225
	Total	45,490	1,537,486	249,985	1,491,230
Sales Volumes (m3 in 2012)					
	Residential	85,280,468	3,206,807,568	449,770,294	2,908,609,482
	Commercial	65,522,055	1,966,788,808	285,725,638	2,236,586,473
	Industrial	76,770,020	1,212,578,171	222,023,205	2,877,751,427
	Total	227,572,544	6,386,174,548	957,519,137	8,022,947,382
DSM Spending (2014)					
	Residential	$ 1,536,730	$ 98,897,476	$ 9,829,100	$ 23,545,912
	Low Income	$ -	$ 38,284,014	$ 4,246,800	$ 5,040,259
	C&I	$ 714,125	$ 33,914,584	$ 5,586,800	$ 12,156,533
	Regulatory/other			$ 370,900	$ 3,995,914
	Total	$ 2,250,855	$ 171,096,074	$ 20,033,600	$ 44,738,618
Annual m3 Savings (2014)					
	Residential	838,806	44,433,623	5,203,928	32,434,937
	Low Income	-	7,443,613	837,362	1,433,803
	C&I	1,776,524	29,231,704	5,541,184	49,782,447
	Total	2,615,330	81,108,941	11,582,474	83,651,187
Lifetime m3 Savings (2014)					
	Total	45,196,622	1,084,138,194	168,723,475	n.a.

b) Mr. Neme does not have access to detailed information regarding the characteristics of large customers in these jurisdictions. As noted in response to a) above, large customers in Minnesota are permitted to opt out of DSM programs. To his knowledge, the utilities in Vermont, Massachusetts and Rhode Island serve all customers, including large customers, with their programs.

Witness: Chris Neme

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

UPDATE AUG. 22, 2013

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.

EB-2012-0451
EB-2012-0433
EB-2013-0074

BEFORE THE ONTARIO ENERGY BOARD

IN THE MATTER OF an application by Enbridge Gas Distribution Inc. for: an order or orders granting leave to construct a natural gas pipeline and ancillary facilities in the Town of Milton, City of Markham, Town of Richmond Hill, City of Brampton, City of Toronto, City of Vaughan and the Region of Halton, the Region of Peel and the Region of York; and an order or orders approving the methodology to establish a rate for transportation services for TransCanada Pipelines Limited;

AND IN THE MATTER OF an application by Union Gas Limited for: an Order or Orders for pre-approval of recovery of the cost consequences of all facilities associated with the development of the proposed Parkway West site; an Order or Orders granting leave to construct natural gas pipelines and ancillary facilities in the Town of Milton; an Order or Orders for pre-approval of recovery of the cost consequences of all facilities associated with the development of the proposed Brantford-Kirkwall/Parkway D Compressor Station project; an Order or Orders for pre-approval of the cost consequences of two long term short haul transportation contracts; and an Order or Orders granting leave to construct natural gas pipelines and ancillary facilities in the City of Cambridge and City of Hamilton.

GREEN ENERGY COALITION (GEC)

FINAL ARGUMENT

Filed: November 15, 2013

David Poch, Barrister
Counsel for GEC

increased investment, plus the increased price of gas, plus the short-haul tariffs, will be less than the reduction in payments to TCPL. Please refer to our submissions below under "Issues A2 & A3 – A Zero Sum Game" for a discussion of this claim from the perspective of the LDC customers and all Ontario gas shippers, including direct-purchase customers and power generators.

Load Growth - Providing Adequate Gas Pressure at Station B

The only truly time-sensitive driver for the GTA projects is the anticipated low pressure problem at Station B, on those infrequent occasions when temperatures drive an extreme peak load.

This issue requires a consideration of several factors including the load forecast, the opportunity for DSM to offset load growth, and the ability to address infrequent and short-lived system peaks with an enhanced approach to interruptible contracts. We review these matters briefly here and we will address the achievability of DSM and interruptible support further under issue A4 – Alternatives.

In Ex. L.EGD.GEC.1, Mr. Chernick charts the data that EGD provided for GTA winter peak loads in recent years against the level that requires pipeline pressures above 30% SMYS (expressed as 100% in the graphic reproduced below). Using EGD's preferred conversion factor for daily to peak hourly flows, the 30% level would be at the 95% level on the graphic.[12] In either case, it is apparent that the loads exceed the 30% SMYS threshold on only a very few days (4 days over 95%) in the three years of data available.

[12] See M.GEC.EGD.1. In J6.6 EGD has indicated that the 165TJ/day reduction in the Don Valley line capacity to achieve 30% SMYS it would convert to 219 10^3m^3 (a 23% reduction) rather than the 181 10^3m^3 (a 19% reduction) Mr. Chernick utilized.

these other purposes (such as the need for the segment to meet load or to supply US gas), it would engage in a circular argument and claim that the facilities were driven by the need to address the 37% 'problem'. As Mr. Chernick elaborated, since access to US gas does not require Segment B and achieving required pressures at Station B is possible with lower-cost demand side options, no triggering event has in fact occurred for Segment B. Enbridge is in effect trying to get the project to pull itself up by its bootstraps.

This is not to deny the fact that lowering pressures to 30% is advantageous. The question is whether 30% must be achieved 100% of the time, and even if that is the conclusion, would a plan to lower pressures over several years as DSM builds be a reasonable alternative?

One might also ask, if 30% SMYS is so urgent, why does Enbridge maintain these lines at 37% throughout the winter season rather than only when needed based on weather forecasts and ramping constraints? Why has Enbridge not pursued DSM to reduce peak demands and lower the pressure on the lines, or even asked the DSM collaborative for assistance in accelerating weather-related load reductions along these pipelines? Why does Enbridge operate 262 kms of line at greater than 30%[17], and why does Union operate 133 different lines (a list 3 pages long) at pressures above 30%[18]?

In Exhibit I.A1.EGD.ED.34 Enbridge specifically noted:

> Enbridge operates all of its pipelines facilities to meet or exceed minimum codes, regulations, and standards. There are no minimum standards relating to operational risk, safety and reliability that will not be met if this project does not proceed.
>
> The project is not justified based on meeting minimum safety standards….

Enbridge did note that the TSSA recently released the Oil and Gas Pipeline Systems Code Adoption Document Amendment FS-196-12 which directs companies such as Enbridge to

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meet our load growth or other challenges on the system, but also incorporate what would be required to be able to reduce pressures on those lines to below 30 percent.

[17] V.5,p.106, V.6, p.76

[18] J4.3

Ontario Energy Board

Commission de l'énergie de l'Ontario

EB-2012-0433

IN THE MATTER OF AN APPLICATION BY

UNION GAS LIMITED

LEAVE TO CONSTRUCT THE PARKWAY WEST PROJECT

EB-2013-0074

IN THE MATTER OF AN APPLICATION BY

UNION GAS LIMITED

LEAVE TO CONSTRUCT THE BRANTFORD-KIRKWALL/PARKWAY D PROJECT

EB-2012-0451

IN THE MATTER OF AN APPLICATION BY

ENBRIDGE GAS DISTRIBUTION INC.

LEAVE TO CONSTRUCT THE GTA PROJECT

DECISION AND ORDER

JANUARY 30, 2014

reinforcement projects but stated that its views generally applied to Union as well. However, GEC did not advance specific arguments against the Brantford-Kirkwall/Parkway D Project based on evidence in the proceeding. The issue of DSM as an alternative is discussed later in this decision in the context of the Enbridge application. There was no evidence that DSM measures would obviate the need for the Brantford-Kirkwall/Parkway D Project. GEC's own witness, Mr. Chernick, did not take a position on Union's applications, but indicated that because the projects relate to switching gas supplies the need for the projects would not be affected by load reductions. As he stated in testimony:

> "I was asked to look at the feasibility and benefits of avoiding additions through load reductions. And since the justification for Segment A and some of the other facilities had to do with switching gas supplies, it really wouldn't have been affected by load reductions." [5]

Similarly, the other evidence related to DSM alternatives (Mr. Neme and Mr. Jim Grevatt on behalf of GEC and Mr. Ian Jarvis, Ms. Wen Jie Li and Ms. Gillian Henderson from Enerlife Consulting on behalf of Environmental Defence) related only to the Enbridge application. The Board finds that there is no evidence that DSM measures would provide a superior alternative to the Union project.

COC opposed all of the applications. COC submitted that the applicants have underestimated the risks of diversifying supply with shale gas while overestimating the benefits. COC also took the position that Canadian gas is preferable to a reliance on U.S. sourced gas. However, Ontario is situated within a continental energy market which has developed over a substantial period of time. The integrated nature of the gas market has brought significant cost and reliability benefits to Ontario consumers. Further, the evidence in the proceeding is that shale production is expected to remain strong and there are no regulatory impediments to ongoing production where it is currently taking place. It is the Board's view that while uncertainties exist for all supply sources in terms of future cost and availability, it is widely acknowledged, including by

[5] Transcript Vol. 7, p. 55-56.

- backup and entry point diversity for the single largest point of risk in the Enbridge franchise – the Parkway Gate Station

Enbridge identified the following transportation benefits:

- access to gas from the U.S. Northeast using short-haul transmission
- greater access to the Dawn Hub

Segment B

Segment B is primarily designed to address load growth, safety and reliability issues. Enbridge forecasts that, by the winter of 2015/2016, the current infrastructure will be unable to supply the required volume of gas at the minimum required inlet pressure at Enbridge's Station B. Station B is the most remote point on the Extra High Pressure (XHP) system from the entry point of gas to the Enbridge GTA franchise area. Without the GTA Project, the inlet pressure at Station B is forecast to drop below the minimum system pressure. With the GTA Project, there will be additional capacity to serve Station B.

Enbridge first identified Station B inlet pressure as a concern in 2002. Enbridge explained that it had deferred construction of the proposed Segment B pipeline on a number of occasions, dating back to 1993, and instead had either procured additional Storage Transportation Service or Firm Transportation capacity. Enbridge noted that its ability to manage the operational risks has become constrained because customer growth has consumed the available capacity in the XHP distribution system.

In addition, the NPS 26 line is the only XHP pipeline connecting the western and eastern parts of Enbridge's distribution system serving the GTA. The smaller NPS 26 connecting pipeline is a bottleneck between the NPS 36 Parkway North line and the NPS 36 Don Valley line. The proposed Segment B would eliminate this east-west bottleneck and allow gas to be available from more diverse supply points and aid in daily load balancing.

Enbridge also noted that Segment B will address operating parameters recently implemented by the Technical Standards and Safety Authority ("TSSA") for pipelines operating at greater than 30% of Specified Minimum Yield Strength ("SMYS") in densely populated or high consequence areas. In order to mitigate the risk of a catastrophic event, Segment B would have an operating pressure below 30% SMYS whereas both the Don Valley and the NPS 26 line operate at greater than 30% SMYS. Enbridge indicated that these have been identified as high priority areas in the company's risk assessment process.

Enbridge explained that it had reviewed a variety of alternatives to the project: using existing pipeline infrastructure on the distribution system or external to Enbridge's system; curtailing existing firm customers; using liquefied natural gas; and contracting for more transportation services. Enbridge concluded that none of these were viable alternatives to the GTA Project. Enbridge also investigated compression alternatives within the distribution system to alleviate the potential of falling below minimum system pressure requirements. This alternative was rejected because it would involve adding compression at numerous locations which is problematic in an urban setting.

While most parties supported Enbridge's application, Environmental Defence, GEC and BOMA opposed the project on the basis that DSM was a viable alternative for all or part of the project. Both Environmental Defence and GEC coordinated to sponsor expert evidence on DSM.

Mr. Ian Jarvis, Ms. Wen Jie Li and Ms. Gillian Henderson from Enerlife Consulting provided expert evidence on behalf of Environmental Defence. Their evidence examined the potential role increased DSM efforts could play in offsetting load growth in the GTA area. Enerlife Consulting concluded that all load growth in the GTA area can be completely offset through commercial and apartment DSM and that overall demand can be significantly reduced with the addition of residential and industrial DSM.

Mr. Chris Neme and Mr. Jim Grevatt from Energy Futures Group and Mr. Paul Chernick from Resource Insight, Inc. provided separate, but related pieces of expert evidence on behalf of GEC. Energy Futures Group provided a companion piece of evidence to that of Enerlife Consulting. Energy Futures Group critiqued Enbridge's assessment of DSM as an alternative and provided an assessment of the potential incremental efficiency savings achievable in the GTA Project area based on the experience of leading jurisdictions. Energy Futures Group concluded that examples from other jurisdictions clearly demonstrate that Enbridge could be capturing much greater savings through aggressive energy efficiency than it has been capturing to date. Mr. Chernick examined the extent to which expanded DSM efforts could defer or avoid some or all of EGD's proposed GTA Project, with a focus on Segment B. Mr. Chernick concluded that Segment B appears to be avoidable through load reductions from a combination of accelerated DSM, expansion of interruptible or curtailment rates for industrial, commercial and apartment loads, and arrangements to reduce the load of the Portlands Energy Centre ("Portlands") (a large combined-cycle power plant served from Station B) on winter design-peak days.

Board Findings

The Board finds that the evidence supports the need for the GTA Project and that no superior alternative has been identified.

COC opposed the GTA Project as a whole for the same reasons it opposed the Union projects. The Board has already explained earlier in this decision in respect of the Union projects why it does not agree with COC's analysis, and the Board adopts the same reasoning in relation to COC's objections to the Enbridge project. The Board does not consider COC's arguments to be a valid basis to deny the application.

Segment A/Parkway Gate Station

Most parties supported Segment A and the Parkway Gate Station, largely for the same reasons they supported Union's Brantford-Kirkwall/Parkway D Project. Enbridge has been guided by the Board's direction in the Union EB-2011-0210 decision. In that proceeding, the Board was concerned with the potential for overbuilding or duplicative infrastructure which would result in adverse consequences to ratepayers. As a result, the Board directed Union Gas, Enbridge and TransCanada to co-operate on building natural gas infrastructure. The Board finds that Enbridge's Segment A, as well as Union's project, are responsive to the Board's direction. Segment A and the Parkway Gate Station alleviate a key transmission bottleneck, enable switching from long haul to short haul transportation services, and provide efficiency and optimization benefits through shared transportation and distribution use.

BOMA, GEC and Environmental Defence objected to Segment A and the Parkway Gate Station to varying degrees, largely for the same reasons BOMA and GEC objected to the Union Brantford-Kirkwall/Parkway D Project. The Board has previously addressed these arguments and has explained why it does not agree with the analysis. The Board adopts the same reasoning as it relates to Segment A and the Parkway Gate Station. As with the Brantford-Kirkwall/Parkway D Project, the Board finds that there is no credible evidence that DSM is a viable alternative to Segment A and the Parkway Gate Station.

Segment B

Most parties supported Segment B as the appropriate way to address customer growth and system reliability and safety concerns. However, a few parties raised objections and concerns with respect to whether the project is needed at this time and whether there were suitable alternatives. The Board will deal with each issue separately and then set out its expectations regarding future planning.

Segment B – Need

Two issues were raised with respect to the need for the project:

- the risk assessment process
- the urgency of the requirement

Environmental Defence submitted that demand growth and gas supply alternatives were the primary drivers for Enbridge's proposal and that reliability concerns were a secondary consideration in the planning process. GEC questioned the rationale supporting pressure as a driver for Segment B, arguing that pressure was not a significant issue in the near or long term as many other lines on Enbridge's system currently operate above 30% SMYS. SEC also noted that a significant number of Enbridge's pipelines operate at or above 30% SMYS. Although supportive of the overall project, SEC submitted that Enbridge's risk assessment was inadequate and argued that the company should have developed or conducted an analysis of its distribution system to determine if and when facilities are needed to address pressure issues.

The Board finds that there was limited evidence that Enbridge undertakes a systematic and transparent risk assessment process for pipeline replacement. Other pipelines on the company's system are over 40 years old and operate at or above 30% SMYS, and Enbridge's prioritization process for determining pipeline replacement is not entirely clear. However, the Board finds that there are reliability issues associated with the NPS 26 and Don Valley Line which need to be addressed. These issues arise from load growth and recent TSSA code changes. Recent experience on the Don Valley Line confirms the existence of a significant physical risk. For any future pipeline replacement or reinforcement proposals, the Board expects to see a more transparent and systematic risk assessment and project prioritization.

While not opposing the project, some parties suggested that Segment B was the least urgent portion of the GTA Project, particularly the north-south Don Valley line, and that it could perhaps be done in stages or the construction start date deferred. The Board finds that Enbridge's evidence is adequate to approve the project now, and that there is no compelling reason to defer the building of Segment B or to stage the construction. The Board accepts Enbridge's evidence that there are cost efficiencies in proceeding with Segment B concurrently with Segment A.

Segment B – Alternatives

Environmental Defence submitted that Enbridge had not established that the GTA Project was the preferred alternative compared to a combination of DSM and increased interruptible service. BOMA provided similar submissions with respect to Enbridge's lack of evaluating DSM as an alternative during its planning. GEC submitted that DSM as an alternative was not properly considered and that Enbridge did not fully evaluate the least cost planning option of increased conservation and/or rate design options.

Rate design options would include interruptible and/or curtailment rates for specific customers. For example, it was suggested that if Portlands were switched to an interruptible service, then the reliability issue would be largely addressed, at least in the short term. Portlands did not participate in the hearing, so it is speculation as to whether it would agree to such an arrangement. However, it is significant that Enbridge did not explore this option or other rate options with key customers. Enbridge explained that it plans its system to meet peak needs and assumes that interruptible loads are on.

The second alternative would be DSM programs. As noted above, both GEC and Environmental Defence provided expert evidence which examined the potential for increased natural gas savings in the GTA to offset or defer Enbridge's proposed GTA Project. Both GEC and Environmental Defence's experts concluded that some or all of Enbridge's GTA Project could be avoided or deferred.

GEC submitted that the Board needs to promote energy conservation and that DSM has proven to be a viable alternative to capital investments with a 4:1 benefit to cost ratio. Further, GEC submitted that concentrated DSM in higher influence areas could address Enbridge's peak issues on Segment B. The added benefit of this option would be greenhouse gas reduction, in accordance with government policy.

Environmental Defence submitted that DSM was a superior alternative to the project. In Environmental Defence's view, load growth and the reliability concern can be adequately addressed using DSM and interruptible rate options. Environmental Defence argued that such an approach would be less risky for ratepayers and would be consistent with government policy.

Many parties submitted that although DSM provides benefits, it was not a viable or reasonable alternative to Segment B. Board staff submitted that increased DSM activity is not a full or partial alternative at this time. In Board staff's view Enbridge's current approaches to DSM and system planning are not directly comparable because system planning is based on peak demand which is not the basis for DSM program planning. SEC submitted that it is not practical to require Enbridge to design and develop new DSM programs to meet an in-service date of winter 2015/2016. However, SEC also noted that Enbridge waited and addressed the pressure issue poorly, eliminating any possibility for targeted or increased DSM as an option.

Enbridge responded that it is fully committed to DSM but that DSM cannot be seen as an appropriate alternative to any portion of the GTA Project. Enbridge noted that the DSM framework is specifically intended to consider annual consumption savings.

Enbridge submitted that the capacity required to reduce the pressure in the Don Valley Line (165 TJ/day) is more than an order of magnitude larger than what Enbridge could achieve through its DSM efforts.

Based on the evidence of GEC and Environmental Defence, the Board accepts that targeted DSM programs and/or rate design options might in some circumstances mitigate the need for Segment B. However, there are significant uncertainties:

- It is uncertain whether DSM or rate design would fully offset the need for the pipeline. For example, Portlands is a firm service customer and presumably selected that option, including paying a substantial contribution in aid of construction, understanding its options. In addition, the intervenor evidence identified the use of 80 buildings for targeted DSM, but Enbridge's evidence is that there are only 42 such buildings in the relevant area.
- Considerable time and resources would be required to substantially re-structure Enbridge's current DSM program. The evidence suggests that the DSM budget would need to triple in size and the nature of the programs would change substantially.
- The impact of targeted DSM programs on Enbridge's peak demand is uncertain as Enbridge does not currently have the necessary analytical tools or information. The current DSM framework is intended to achieve annual consumption savings.
- The cost of the DSM programs is uncertain. It would be important to understand the costs and rate impacts as part of the analysis of the alternatives.

These uncertainties are significant because of the timing for Enbridge's requirement and the lack of documented success of this approach in another similar situation involving a gas utility. The Board accepts the company's evidence related to the timing in which the reliability and load growth issues must be addressed, given the physical system risks involved, and concludes that DSM and/or rate design options are not a sufficiently viable alternative in these circumstances to warrant denial of the project.

GEC and Environmental Defence also argued that the project should be rejected on the basis that Enbridge's planning approach was inadequate. The Board does not agree. Enbridge claimed to have considered DSM alternatives, but the consideration was cursory at best. The evidence is clear that no staff with DSM expertise attended the relevant meetings. Enbridge acknowledged that it had not conducted integrated resource planning[9] and argued that it could not have been expected to do so. The company conducted its planning, and the assessment of alternatives, within the context of the current regulatory framework and the current framework for DSM. The Board finds that this approach was reasonable in the circumstances.

Future Planning

Environmental Defence urged the Board to send a signal to the companies that new supply-side investments will not be approved unless all lower cost DSM and/or interruptible service options have been explored and documented. Other parties agreed and argued that both Enbridge and Union should be required to do a better job at properly incorporating DSM into system planning, with some parties suggesting that both companies should be required to conduct integrated resource planning.

Enbridge responded that if the Board decides to consider integrated resource planning within the DSM framework, or more broadly in a generic hearing, Enbridge would be willing to take a leadership role. Enbridge was supportive of a generic hearing regarding the role of geographically targeted DSM programs under an integrated resource planning framework, including addressing some of the suggestions from Environmental Defence, GEC and BOMA.

In light of the evidence presented, the Board concludes that further examination of integrated resource planning for gas utilities is warranted. The evidence in this proceeding demonstrates that the following issues should be examined:

- The potential for targeted DSM and alternative rate designs to reduce peak demand

[9] An integrated resource plan is a utility plan for meeting demand through a combination of supply-side and demand-side resources.

- The role of interruptible loads in system planning
- Risk assessment in system planning, including project prioritization and option comparison
- Shareholder incentives

There will undoubtedly be other issues as well. The Board notes that this review is particularly timely given the recent provincial Long Term Energy Plan. Further information on how the Board will examine gas integrated resource planning will be released in due course.

Pending that review, the Board expects applicants to provide a more rigorous examination of demand side alternatives, including rate options, in all gas leave to construct applications.

4.2 Project Costs, Economic Evaluation, Rate Impact (including Rate 332)

Enbridge estimated the cost of the GTA Project to be $686.5 million. Segment A is estimated to cost approximately $384 million, including the Parkway West Gate Station, while Segment B is estimated to cost approximately $302 million. Enbridge conducted economic feasibility calculations for the GTA Project in accordance with both E.B.O 188 and E.B.O. 134. Based on Enbridge's analysis, the PI of the GTA Project is 1.73 and the NPV is $667 million. Enbridge also conducted sensitivity analysis scenarios: 10% higher capital costs; zero transmission revenue from shippers on Segment A; 25% and 50% lower transportation cost savings. Under these scenarios, either individually or collectively, the GTA Project is still economically feasible in Enbridge's analysis. Because the economic feasibility results are positive, the company only performed a Stage 1 analysis. However, Enbridge maintained that the evidence shows that Stage 2 benefits would be substantial for consumers using natural gas as opposed to other fuels. Enbridge also noted that the reliability benefits of GTA Project were not monetized, and are not part of the economic feasibility calculations, but are of significant value.

ENBRIDGE INTERROGATORY #15

INTERROGATORY

Reference: Exhibit L.OEBStaff.1, page 128

Question:
Please provide the report by Neme & Grevatt relating to the deferral of utility infrastructure through targeted DSM.

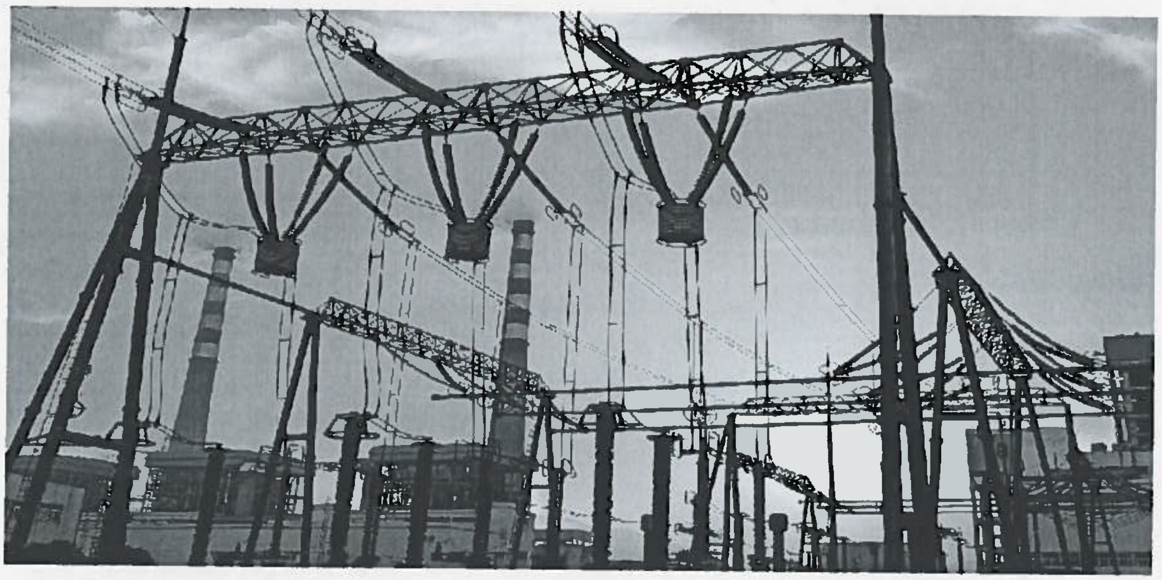
RESPONSE

Please refer to Exhibit M.Staff.EGDI.15, Attachment 1. This report is listed in the Reference section of the report,[7] and can be accessed here: http://www.neep.org/energy-efficiency-transmission-and-distribution-resource-using-geotargeting-report-0

[7] See Neme, C., & Grevatt, J. (2015). *Energy Efficiency as a Transmission and Distribution Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments.*

Witnesses: T. Woolf
K. Takahashi
E. Malone
J. Kallay
A. Napoleon

Northeast Energy Efficiency Partnerships



Energy Efficiency as a T&D Resource:

Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments

January 9, 2015

Chris Neme & Jim Grevatt, Energy Futures Group

estimates of avoided T&D costs are typically developed by dividing the portion of forecast T&D capital investments that are associated with load growth (i.e., excluding the portion that is associated with replacement due to time-related deterioration or other factors that are independent of load), by the forecast growth in system load. Such estimates can vary considerably, often as a function of the utilities' assumptions regarding how much investment is deferrable. For example, in New England, utility estimates of avoided T&D costs currently range from about $30 per kW-year (CL&P) to about $200 per kW-year (National Grid – Massachusetts).[14]

Like passive deferrals, the benefits of active deferrals are a function of the value of each year of deferral and the length of the deferral. However, because the deferral of a specific T&D investment is the primary objective rather than by-product of the efficiency programs, benefits are always very project-specific. Examples of such benefits are provided in the following sections of this report.

It is important to recognize that deferred T&D investments – whether passive or active – are a subset of the benefits of the efficiency programs that produced the deferral. Efficiency programs always also provide energy savings to participating customers, reductions in line losses, and environmental emission reductions. They also typically provide system peak capacity savings, reduced risk of exposure to fuel price volatility and, particularly in jurisdictions with competitive energy and/or capacity markets, price suppression benefits.

Applicability to Natural Gas Infrastructure

Though this report focuses primarily on the role that efficiency programs can play in actively deferring *electric* T&D investments, the concepts are just as applicable to gas T&D infrastructure investments. That is, natural gas efficiency programs are likely to be passively deferring some gas T&D investments and, under the right circumstances – e.g. for load-related T&D needs, with enough lead time, etc. – should be viable options for deferring some gas T&D investments.

The passive deferral benefits of gas efficiency programs have either not been widely studied or not been widely publicized. However, there are at least a couple of examples worth noting. First, Vermont Gas Systems (VGS) routinely includes the impacts of its efficiency programs in its integrated resource planning (IRP). As noted in its revised 2012 IRP, efficiency programs are forecast to not only reduce gas purchases, but also contribute to "delayed transmission investment during the term of (the) plan."[15] In its 2001 plan, VGS was even more explicit, concluding that its efficiency programs would produce sufficient peak day savings to delay implementation of at least one transmission system looping project by one year.[16]

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[14] Hornby, Rick et al. (Synapse Energy Economics), *Avoided Energy Supply Costs in New England: 2013 Report*, prepared for the Avoided Energy Supply Component (AESC) Study Group, July 12, 2013.
[15] Vermont Gas Systems, Inc., *REVISED Integrated Resource Plan*, 2012.
[16] Vermont Gas Systems, Inc., *Integrated Resource Plan*, 2001.

We are not aware of any publicly available documentation of examples in which a gas utility has used geographically-targeted efficiency programs to *actively defer* a T&D investment. However, there may be growing interest in this topic. For example, following a hotly contested proceeding on a very large gas pipeline project, the Ontario Energy Board recently concluded that geographically-targeted efficiency and demand response programs might have been able to mitigate the need for a portion of the project designed to meet growing loads in downtown Toronto, but "significant uncertainties", mostly related to time limitations and to Enbridge Gas' (the local gas utility's) lack of information on and experience with assessing peak demand impacts of its efficiency programs, led it to approve the project as proposed. However, the Board also stated that "further examination of integrated resource planning" is warranted and that it "expects applicants to provide more rigorous examination of demand side alternatives" in all future proposals for significant T&D investments.[17] In a very different context, some parties have suggested that geographic targeting of gas efficiency programs to areas near gas-fired electric generating stations could help alleviate pipeline congestion that is driving up the winter cost of electricity in parts of New England.[18] It is conceivable that such efforts might also help defer the need for some gas T&D investments.

NEEP will be undertaking a 2015 scoping project to document what gas system planners would need to assess the potential viability of demand-side alternatives to gas T&D investments.

[17] Ontario Energy Board, *Decision and Order*, EB-2012-0451, in the matter of an application by Enbridge Gas Distribution, Inc. Leave to Construct the GTA Project, January 30, 2014.
[18] Schlegel, Jeff, "Winter Energy Prices and Reliability: What Can EE Do to Help Mitigate the Causes and Effects on Customers", June 11, 2014.

Before the Ontario Energy Board

EB-2006-0021

An Effective Policy Framework for Gas DSM in Ontario

Prepared by:

Chris Neme & Glenn Reed
Vermont Energy Investment Corporation

For:
The Green Energy Coalition
David Suzuki Foundation
EnerAct
Greenpeace Canada
Sierra Club of Canada

June 2, 2006

> *"…it seems unlikely that this [procurement] program is creating any new savings."* (p. 12)

A similar problem occurred in the context of Enbridge's TAPs programs, where its service delivery contractors were initially only installing efficient showerheads to homes in which bag-tests demonstrated that the old showerheads were inefficient. Enbridge later stopped the testing but continued to claim the same savings and free rider rates until challenged by GEC.

3.3 What certainty is required that the assumptions are set for the duration of the DSM plan?

Answer

There is value in "locking in" assumptions – at least for a year at a time – on variables that the utility cannot affect without changing program designs, but only for the purpose of determining whether or not the utilities have met TRC performance targets and for calculating shareholder incentives. Even then, if the utility changes its program designs in a way that could affect what would otherwise be prescriptive assumptions, best available information should be used to compute the TRC net benefits that will be used to determine whether performance targets have been met and the magnitude of shareholder incentives to which the utility may be entitled. This is consistent with current shareholder incentive rules for both EGDI and Union (sometimes referred to as the 2003 rules). Computations of LRAM adjustments should *always* be based on the best available information, irrespective of previous assumptions.

Rationale

The principal purpose of a shareholder incentive mechanism is to encourage a DSM provider to excel in the delivery of DSM services. To that end, the utility should be held accountable only for variables over which it has direct control. That is why it is reasonable to lock in, for example, assumptions regarding per unit savings for programs promoted to mass markets. It is also why it is not reasonable to lock in assumptions for custom measures promoted to individual (usually large) customers. Finally, it is why it is reasonable to change assumptions used to compute program results (but not the performance targets) if the utility has changed its programs in a way that can be anticipated to generate different levels of savings, costs, free ridership, etc.

That said, it may be problematic to "lock in" prescriptive assumptions for a full three-year term, even for just determining eligibility for shareholder incentives, because our understanding of savings that DSM measures and programs generate can change both significantly and fairly quickly. It is important that the DSM rules encourage utilities to make appropriate mid-course modifications rather than continuing with old strategies simply because they can earn shareholder incentives. For example, if an evaluation that becomes available six months into a three-year period suggests that the free rider rate for an important program is 90% rather than the 30% that was previously assumed, we should want the utility to shift spending away from that program and into more productive programs. To not encourage them to do so would be a major disservice to rate-payers – both because they would pay for a program that did not generate much savings and because they would potentially be rewarding the utility for good performance on a program that did not generate much benefits. Thus, there should be a mechanism for annually adjusting prescriptive assumptions. The Evaluation and Audit Committee(s) are the ideal mechanism for reviewing and recommending such changes. Any changes recommended by the Committee(s) should be applied on a forward-going basis (i.e. from the next annual anniversary date of the plan) so that the utility which has relied on the previous assumption is not penalized for past actions.

LRAM is different. Its purpose is to ensure that (1) the utility does not lose revenue as a result of achieving greater DSM savings than anticipated, or (2) ratepayers do not pay more in rates than necessary because their utility over-forecast DSM impacts. To that end, there is no reason to use "locked in" assumptions for LRAM account clearances. If the plan assumed greater savings than actually occurred, using locked in assumptions would pay the utility for revenue it did not lose. Conversely, if the plan assumed lower savings than actually occurred, using locked in assumptions would under-compensate the utility for lost revenues. The utilities have argued that these two effects will cancel each other out over time. However, empirical data from gas DSM in Ontario demonstrates that such a presumption is wishful thinking, at best. For the three years Union has had an audit of its DSM savings, post-audit savings estimates have been lower than pre-audit estimates every year. Over the three years, post-audit values are 82% of pre-audit estimates. Similarly, over the last two years of Enbridge's audited results, actual savings have been 88% of pre-audit estimates. In addition, the presumption that planning estimates will be an equal mix of under-estimate and over-estimates of actual savings ignores the reality that if assumptions are locked in for LRAM the utilities will have an added incentive to err on the high side in their planning estimates. While GEC and others may be able to identify and convince the Board to fix a number of those errors, the effects of such an approach would be the opposite of the stream-lining of the regulatory process that the utilities have argued is so important. Moreover, placing the burden of proof on intervenors would be particularly problematic under the utilities' proposals in which they alone decide what evaluation work to do, who to share the results with and when to do so.

3.4 What is the mechanism to determine if an input assumption needs to be reviewed or researched?

Answer

The mandate of existing Audit Committees should expanded so that they become Evaluation and Audit Committees with ongoing (rather than just once a year – at audit time) responsibility for assessing the reasonableness of DSM assumptions that the companies propose. To that end, they should be responsible for prioritizing and managing evaluations of independent evaluation contractors, as well as managing and the annual audit. Three percent of the utilities' DSM budgets should be set aside for these purposes. As part of the process of determining which DSM assumptions should be

ENBRIDGE

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August 25, 2015

VIA RESS, EMAIL and COURIER

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, ON M4P 1E4

Dear Ms. Walli,

**Re: Enbridge Gas Distribution Inc. (the "Company" or "Enbridge")
Ontario Energy Board (the "Board") File: EB-2015-0049
Multi-Year Demand Side Management Plan (2015 to 2020)
Evidence in Chief – Panel 4**

Enclosed please find the Evidence in Chief for Enbridge's Panel 4.

The submission has been filed through the Board's Regulatory Electronic Submission System ("RESS").

If you require further information, please contact the undersigned.

Yours truly,

(Original Signed)

Bonnie Jean Adams
Regulatory Coordinator

cc: Mr. Dennis O'Leary, Aird &Berlis
EB-2015-0049 Intervenors

Evidence in Chief – Hilary Thompson

Q: Can you please comment on Mr. Chernick's revisions to Enbridge's Avoided Distribution costs identified in Exhibit L.GEC.2 Table 8 on page 41?

A: Ms. Thompson

Mr. Chernick completed a review of Enbridge's Avoided Distribution Costs and concluded that they should have been 3.4 to 4.7 times higher than the costs that Enbridge used. I would like to demonstrate that Enbridge appropriately reflected the Avoided Distribution Costs and that no revisions need to be made apart from the ones that have been indicated by Enbridge.

Area 10 and Appendix B

Starting with Table 8 on Page 41, under "Corrections", Mr. Chernick refers to Area 10 and Appendix B. These were inadvertent omissions that were identified through the course of the interrogatory responses. These omissions amount to approximately $55M, which is a 27% increase to the costs that were originally provided to Navigant. It is important to note that this 27% increase results in a marginal increase to the Avoided Distribution Costs Adder of less than 1% in the Water Heating and Industrial load profiles, and less than 2% in Space Heating and Space and Water Heating load profiles as indicated in the response to Undertaking JT1.28.

Enbridge is currently in the process of doing a complete update to the reinforcement project list for the Q4 Input Assumption Update. Enbridge feels that this is appropriate since the identification of the projects is now up to 2 to 3 years old and many changes can occur within the distribution system that would change the reinforcements (i.e., changes in load growth, changes in development projections, changes in system operation, etc.). For the Area 10 projects alone, we know that some projects will remain on the list, others will be added, and some will drop off because they are either no longer required or are not required to address load growth and would not be an avoided cost. Based on this, the latest forecast for Area 10 is expected to be approximately half of the above estimate but this will be confirmed as part of the Q4 update.

2010 – 2012 Revisions

Mr. Chernick compared the 2010-2012 Asset Plan actuals to the 2010-2012 actuals provided to Navigant as an input into the Avoided Distribution Costs. Mr. Chernick concluded that $17.4M was missing from the information provided to Navigant.

The main point that I would like to raise here is that all reinforcement projects are not necessarily an avoided cost in relation to DSM. The actual costs from 2010-2014 were reviewed in that manner – to identify the true avoided costs – to ensure that the Avoided Distribution Costs were a reasonable derivation of the costs that fit into this category and were not inflated or deflated.

For example, in the costs for the 2010-2012 Asset Plan, it included the transition of an old gate station into a straight run of pipe that was approximately $3M, the installation of a project that directly supported a new industrial customer load at approximately $1M, and sales projects that directly supported customer attachments at approximately $5M – none of which fit within the category of avoided costs. In addition, approximately $8M of costs for the GTA Project was included which I will discuss in more detail in a moment. This speaks to why the numbers are different for specific and intended purposes and why no corrections are required to this line item.

GTA Project

For GTA Project, Mr. Chernick concluded that additional GTA Project costs should be included in the Avoided Distribution Costs above and beyond the costs that were already included for load growth. I can confirm that the portion attributable to load growth was included in the Avoided Distribution Costs.

Mr. Chernick's table suggests that further costs associated with Segment B should be included, however as noted on page 45 of the Board's Decision for the GTA Project (EB-2012-0451, dated January 20 2014), it found that DSM was "not a sufficiently viable alternative in these circumstances" in relation to alternatives considered. In general, the Board's GTA Project Decision acknowledged that the project addressed multiple needs. More specifically, the Board acknowledged that Segment B addressed load growth, eliminated the bottleneck between the western and eastern part of the system, and allowed for the pressure reduction of the Don Valley and NPS 26 lines to less than 30% SMYS in relation to the code adoption document issued by the Technical Standards and Safety Authority. The GTA Project costs that addressed these other objectives, such as increasing supply chain diversity and flexibility, were not included since they would not be an avoided cost.

This addresses all the corrections that Mr. Chernick noted in his Table 8. In summary, the only revision that needs to be made is the inclusion of the projects that were missed by Enbridge following the full update to the reinforcement projects which were identified, as I noted earlier, and were included in Enbridge's response to Undertaking JT1.28. All other line items should go to $0.

O&M Costs

Q: Can you please comment on Mr. Chernick's conclusion in respect to O&M avoided costs?

A: Ms. Thompson

Mr. Chernick suggests that Enbridge should have included O&M costs for 1% of the investment. Enbridge used 0% since the incremental pipe installed per year is not considered in the development of the annual O&M budget as mentioned in the response to GEC Interrogatory 59.

Mr. Chernick looked back to the O&M costs for the GTA Project and noticed that $13M of O&M was identified for the $687M project. This O&M cost expressed as a percentage in relation to the total project cost is 1-2% as Mr. Chernick stated in his evidence. It is important to note that the majority of the $13M of O&M costs is directly related to the attachment of the forecasted customers (such as costs to support customer care and billing). Since DSM does not aim to defer or avoid the attachment of customers, only the costs associated with the reinforcements should be considered in this calculation. Using Mr. Chernick's approach, the applicable percentage drops to 0.01% with the portion of Segment B that is attributable to load growth, which is immaterial. This confirms the use of 0% O&M assumption for the Avoided Distribution Cost calculation.

Relocations, Replacements, and Sales

Q: Can you please comment on Mr. Chernick's recommendations in regards to the inclusion of relocation, replacement, and sales mains in the Avoided Distribution Costs?

A: Ms. Thompson

In the development of the Avoided Distribution Costs, Enbridge referenced back to a previous filing, EBRO 487, which is filed at Exhibit I.T9.EGDI.GEC.51, Attachment 1. On page 21 of this attachment, it outlines the categories of distribution main expenditures – reinforcement, sales, relocation, and replacement. Through the course of this initial study, it was determined that reinforcement mains were the primary category of avoided distribution system costs affected by load reduction, and therefore, the Company generally limited the inputs to this expenditure type.

The last two paragraphs on page 21 of the attachment referenced states:

> *The other categories of distribution main costs were excluded because they would not be materially affected by load reduction DSM programs. Sales mains are primarily smaller diameter mains. Sales mains costs were not included in the Company's estimate since the DSM programs under consideration are not expected to increase or decrease the number of customer additions.*
>
> *Relocation and replacement mains were excluded because expenditures on these facilities are driven by factors such as routine maintenance and conflicts with other developments, such as road improvement. The need for these facilities is not related to demand.* I should mention to the extent that Enbridge knew about upcoming projects that were upsized to accommodate future growth, the costs associated with the growth component were included in the forecast provided to Navigant.

I should mention to the extent that Enbridge knew about upcoming relocation or replacement projects that were upsized to accommodate future growth, the costs associated with the growth component were included in the forecast provided to Navigant.

In summary, Enbridge feels that it has been consistent with the inputs to the Avoid Distribution Costs as compared to previous years.

Q: Mr. Chernick referenced a relocation project that added capacity to the system. The project was called the Municipality of York Pipeline Project (EB-2011-0270). Can you comment on Mr. Chernick's observations?

A: Ms. Thompson

Enbridge had a 4" and an 8" line along Ninth Line in Markham near 19^{th} Avenue. The region was widening Ninth Line from 2 lanes to 4 lanes and asked Enbridge to relocate the two gas mains and only install one main in its place. To maintain the capacity of the 4" and 8" with one gas main, Enbridge at a minimum had to replace it with a 12" since the Company does not install 10" pipe. The increased capacity of the 12" was incidental to the replacement project and not driven by load.

Evidence in Chief – Andrew Welburn

Q. Do you have any comments about the position advanced by GEC in relation to price suppression effects?

A. Mr. Welburn:

Yes. The supply and transportation price impacts resulting from a reduction in demand that were discussed by GEC are the result of only looking at a select few considerations. If the Board is to consider such impacts, it will be important to take a more broad perspective of market influences. One example would be to consider the implications of lower commodity costs. If there is a decrease in market prices as a result of Enbridge's DSM programs, there is the potential for the lower commodity prices to influence the level of natural gas production. Should natural gas production decline, it could lead to an increase in natural gas prices.

Q. Do you have any view about whether Enbridge's DSM programs result in price suppression across North America?

A. Mr. Welburn:

Although we have considered the concept of price suppression effects when evaluating commodity price information provided by independent third party experts, we are not aware of any studies specific to the markets we operate in. We do not believe there is sufficient information to make that determination especially given the complexity of having storage near the franchise and the unique nature of services such as multi-point balancing in the Union Gas franchise.

It is also important to consider the magnitude of Enbridge's DSM program which makes up less than 1% of the Company's annual demand. It is not clear at this time if demand reduction of that magnitude will influence prices in a meaningful way, if at all, given the more significant impact that other factors such as weather and new infrastructure that is being proposed and developed that continues to increase the integration of North America's market.

Evidence in Chief – Trent Winstone

Q: Mr. Winstone, Mr. Chernick makes comments about Navigant's apparent use of a real carrying charge in its avoided distribution cost study. Do you have any comments about Mr. Chernick's observation and the position that he has taken?

A: Mr. Winstone:

Mr. Chernick concludes that Navigant used a real carrying charge of 5.9% instead of a nominal carrying charge, and in order to correct for this error, applies a 7.7% carrying charge in his revised avoided cost calculations. This adjustment is not correct as the Navigant methodology does not include a carrying charge. The Navigant methodology calculates the difference in revenue requirement attributable to the deferral of a capital investment. As such, no adjustment to Navigant's study are required.

PROVINCE OF ONTARIO

BEFORE THE ENERGY BOARD

2015-2020 DSM Plans of Enbridge Gas)	
Distribution and Union Gas)	**EB-2015-0029/0049**

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE GREEN ENERGY COALITION

Resource Insight, Inc.

JULY 31, 2015

Corrected August 12, 2015

Table 6: Union Avoided versus Average Commodity Charge
(Dollars per Cubic Metre)

	Avoided Commodity Cost		Avoided Minus Average Commodity[a]	
	Res/Com Baseload	Res/Com Weather-Sensitive	Res/Com Baseload	Res/Com Weather-Sensitive
2015	0.173	0.176	0.022	0.025
2016	0.159	0.161	0.007	0.009

[a]Assumes $0.151/m^3 commodity rate

Q: What is the significance of the differentials you discuss above?

A: Unlike the other components I discuss in this section, these differentials between avoided commodity costs and average commodity costs are included in the utilities' avoided costs (although they appear to be understated). The significance of the avoided-to-average differentials is that they should be reflected as benefits to non-participants in the assessment of rate effects.

D. Avoided Distribution Costs

Q: How do the utilities estimate avoided distribution costs?

A: Enbridge provided some cost and load data to its consultant, Navigant, which converted those values to an estimate of avoided distribution costs. Union manipulated the Enbridge estimate of avoided distribution costs to derive an estimate of its avoided distribution costs.

Q: Do the utilities' avoided costs include their local transmission costs, or only distribution?

A: That is not clear.[22] The distinction between transmission and distribution mains varies from one document or application to another. In general,

[22]Obviously, no Union transmission costs are directly reflected in its avoided costs, since it used only Enbridge results.

Enbridge and Union appear to define "transmission" to mean "for wholesale transactions" and "distribution" to mean "for our retail customers." Hence, a single line can be considered to be partially transmission and partially distribution.

Enbridge claims that "transmission, or upstream, avoided costs, such as commodity, transportation and storage costs, were fully captured in the existing avoided gas cost methodology" (Exhibit I.T9.EGDI.GEC.33a), and considers the costs included in Exhibit C, Tab 1, Schedule 4 to be distribution costs.

Enbridge's consultant Navigant entitled its report "Enbridge Avoided Transmission & Distribution Costs," but says,

> During the initial discovery stage of this assignment it was determined that Enbridge's upstream or transmission avoided costs are already fully and accurately captured in their existing avoided cost analysis. The objective was subsequently modified from a study of both transmission and distribution avoided costs to only include the determination of the distribution or downstream avoided costs." (Enbridge Exhibit C, Tab 1, Schedule 4, at 4).[23]

In its presentation for the first workshop with Enbridge, Navigant reviews the avoided costs of a few gas utilities and finds that only one includes capacity as avoidable (Exhibit JT1.23, Attachment 1). In its presentation for the second workshop, Navigant asserts that "Enbridge's existing avoided cost calculation methodology (using Sendout) captures all upstream costs" (Exhibit JT1.23, Attachment 2, at 4). As I discuss in Section III.E.1, Enbridge has not provided on discovery any documentation that

[23]Enbridge has not provided the basis for that "determination," nor any breakout of the avoidable upstream transmission costs.

would have allowed Navigant to reach this conclusion, even though such documentation was requested in GEC 49 and Undertaking 1.23.

Union refers to its reworking of Enbridge's estimate of avoided distribution costs as avoided T&D or infrastructure costs, but makes no effort to include avoided transmission infrastructure.

1. Enbridge

Q: How did Navigant estimate Enbridge's avoided distribution costs?

A: Navigant indicates that Enbridge "provided Navigant with both actual and forecast reinforcement expenditures" (Enbridge Exhibit C, Tab 1, Schedule 4, at 19) for 2010–2019, totalling \$189 million (ibid., Figure 3). While Figure 3 does not specify whether the costs are in nominal, real, or a mix of costs, Navigant reports an average of \$19 million annually over the ten years in 2015 dollars (ibid. at 20).[24]

Navigant also reports average annual growth in design-day peak for 2010–2019 of 1,047 10^3m^3 (ibid., Figure 4). That would imply a distribution investment of \$18,050/10^3m^3 of load growth. Oddly, Navigant never reports this critical value.

Navigant annualizes the \$18,050/10^3m^3 using an idiosyncratic approach, which is described generally at 22–26 of the report, in a section entitled "Detailed Methodology." Unfortunately, Navigant does not provide the details of its computations or even the results in dollars/year per 10^3m^3 of peak load reduction. Backing out the annual cost from the \$/10^3m^3 values in Table 7 of the report and the peak-to-annual ratios in Table 9 results in an

[24]Enbridge has not provided the underlying data, so we cannot check whether all the costs were actually in 2015 dollars.

annual peak cost of about \$1,070/10^3m^3 of peak-day load. In turn, that value indicates that Navigant effectively applied a 5.9% nominal carrying charge to the investment.

Finally, Navigant converts its estimate of avoided distribution costs to dollars per 10^3m^3 of avoided deliveries (over the year, not on the peak day), using the ratios of peak-day 10^3m^3 to annual 10^3m^3 in Table 9 of the report. These values are reported in Table 7, labeled as nominal dollars per 10^3m^3/peak demand day, even though the values are clearly intended to be costs per annual 10^3m^3.[25]

Thus, Enbridge's estimate of avoided distribution comprises the following six steps:[26]

1. Compile load-related investments over a decade.
2. Determine expected design-day peak over that same period.
3. Divide (1) by (2) to estimate the required investment per 10^3m^3 of peak growth.
4. Multiply (3) by a carrying charge to estimate annual avoided cost per 10^3m^3 of peak growth.
5. Estimate the ratio of design-day peak load contribution to annual consumption by rate class.

[25]Errors of this sort, along with inconsistencies in Enbridge's responses and Enbridge's failure to provide data, make reviewing Enbridge's work very difficult. Enbridge refused to provide its analyses, computations and workpapers supporting the derivation of the avoided distribution costs (e.g., Exhibit I.T9.EGDI.GEC.49, 59).

[26]Some of the steps were conducted by Enbridge and some by Navigant. For simplicity, I will refer to the derivation of avoided distribution costs as Enbridge's method.

6. Multiply (4) by (5) to estimate avoided cost per 10^3m^3 of reduced throughput.

These are all standard steps in estimating avoided distribution (and often transmission) costs.

Q: Did Enbridge properly carry out this analysis?

A: No. Enbridge appears to have made mistakes in steps 1, 2, 4, and 5 (load-related distribution investment, associated load growth, the carrying charge, and the load shape). In addition, Enbridge omitted all load-related distribution O&M costs. I will comment on each of these problems in turn.

a) Load-related Distribution Investment

Q: Did Enbridge include all its load-related investments in the 2010–2019 period?

A: No. Enbridge acknowledged omitting some cost categories, its two tabulations of projects in the attachments to Exhibit I.T9.EGDI.GEC.56 are inconsistent, and it has clearly understated the costs of the GTA project.

Q: Which cost categories did Enbridge acknowledge omitting?

A: Enbridge acknowledged omissions in its identification of distribution reinforcement projects (Exhibit I.T9.EGDI.GEC.56 and 57).

> The reinforcement expenditures for Area 10 and Appendix B were inadvertently omitted from the information provided to Navigant. In addition, an equation error was made in the spreadsheet that was used by Enbridge to provide the reinforcement expenditures to Navigant that double counted the years from 2010 to 2012.
>
> The reinforcement projects in Area 10 are those that were listed in … Exhibit I.T9.EGDI.GEC.57. The reinforcement projects in Appendix B are those that can be found in…Exhibit I.T9.EGDI.GEC.56. (Undertaking JT1.28)

The reinforcement projects in Area 10 (the GTA) in Exhibit I.T9.EGDI.GEC.57 for 2017–2019 were listed in the GTA proceeding (EB-2012-0451) as having cost estimates totaling $50.4 million.[27] The Appendix B projects in Exhibit I.T9.EGDI.GEC.56 are listed at $5.9 million. Enbridge reports that these two categories would total "approximately $55M," which may or may not be consistent with the values reported in the GTA proceeding and Exhibit I.T9.EGDI.GEC.56, depending on the dollars in which each estimate is stated. The cost estimates of the GTA proceeding may have been updated since they were filed in 2012.

Q: What are the inconsistencies between the tabulations of reinforcement projects in Attachment 1 and Attachment 2 of Exhibit I.T9.EGDI.GEC.56?

A: Attachment 1 does not have most pre-2014 projects, since it is a response to a request for forecast additions. From 2014 through 2019, Attachment 1 (the list of projects included in the forecast reinforcement expenditures from 2014 to 2019 in the Navigant analysis) lists some 44 projects, while Attachment 2 (the list of the projects included in the Navigant analysis) lists some 32 projects.[28] 21 projects appear in both lists, while Attachment 1 has 23 projects that do not appear in Attachment 2, and Attachment 2 has 11 projects

[27]It is not clear in what year's dollars these estimates, or any of Enbridge's cost estimates for future projects, are listed.

[28]The Attachment 1 is listed as Table 13 to 21 and Appendix B of some unidentified document, which appears to be the "EGDI planning document from which the forecast reinforcement expenditures from 2014 to 2019 were taken," as requested in GEC interrogatory 56. If Enbridge had provided the entire requested document, some of the discrepancies in its analyses might be easier to reconcile.

that are not listed in Attachment 1. Some of these discrepancies may result from the renaming of projects, and Enbridge says that three of the Attachment 1 projects not listed in Attachment 2 have minimal costs, but it still appears that neither list was complete. Unfortunately, Enbridge has not revealed what projects it included in the data provided to Navigant.

Strangely, while Attachment 2 lists the GTA project in 2015, Attachment 1 does not list the GTA at all.

Q: Are there other inconsistencies in the Enbridge data on capital additions?

A: Yes. In the Asset Plan filed in its last rate case (EB-2012-0459, Exhibit B2, Tab 10, p 53), Enbridge reports reinforcements much higher than those in Figure 3 of the Navigant report. See Table 7.

Table 7: Comparison of Reported Historical Reinforcements

	Navigant Figure 3	2012 Asset Plan
2010	\$1.67	\$7.05
2011	\$1.58	\$4.74
2012	\$8.71	\$15.47

Since the Navigant data appear to be in real 2015 dollars and the Asset Plan is in nominal dollars, the Asset Plan's costs would be a little higher restated in the terms of the Navigant report. It is not clear how the mains reinforcements in 2010–2012 could have declined in the past couple of years.[29]

[29]The Asset Plan also projected 2018–2019 additions about $55 million higher than reported for those years in Navigant's Figure 3.

Q: What GTA costs should have been included in the list of reinforcements?

A: The GTA project consisted of Segment A, which Enbridge classified as 40% related to serving distribution load and 60% related to serving wholesale transmission load, and Segment B, which Enbridge classified as entirely related to distribution load (Exhibit I.T9.EGDI.GEC.52). The investments classified as distribution are all load-related reinforcements.[30] Enbridge excluded some of the costs of the GTA distribution investments from the analysis:

> Reinforcement costs for larger projects such as the GTA Project were adjusted to reflect the proportion of the project costs that were directly attributable to load growth. The reinforcement costs of the GTA Project were captured in the costs shown in year 2015 in EB-2015-0049 Exhibit C, Tab 1, Schedule 4, Figure 3. (Exhibit I.T9.EGDI.GEC.33b)
>
> The reinforcement costs as shown in Figure 3 include the Ottawa Reinforcement and the GTA Reinforcement costs. Since these projects had multiple drivers, only the costs associated with load growth were included. (Exhibit I.T9.EGDI.GEC.56d)

In Exhibit JT1.17, Enbridge justifies those exclusions as follows:

> [The] minimum pipe [for the GTA] required a NPS 36 build from Sheppard Avenue to McNicoll Avenue, paralleling the existing Don Valley line, to support 10 years of anticipated load growth. This pipeline segment was estimated to cost $40M to $50M.

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[30]One justification for Segment B was reducing pressure on part of the system; load growth had already exceeded the level at which Enbridge could serve all load at the lower pressure that Enbridge considered prudent. Lower load growth in the GTA would have avoided the need for Segment B.

> For the Ottawa Reinforcement Project, it was estimated that 19 km of NPS 16 would be required from Richmond Gate Station, including a rebuild of the gate station, to support load growth only. This project scope was estimated to cost $46M. It should be noted that this is the same alignment as the approved reinforcement project.[31]

The distribution portions of the GTA project (adjusting proportionately the costs provided in the GTA proceeding for each segment by the increase in the total project cost reported in EB-2015-0122, Exhibit D.1.2) are roughly as follows:

- $400 million for Segment A (justified primarily to import additional US gas, and hence more properly a supply cost),
- $200 million for Segment B1,
- $125 million for Segment B2.

These are large investments compared to the $189 million that Enbridge included as the load-related costs for the entire ten-year period.

Q: Are there other categories of load-related investment costs that Enbridge excluded from its analysis?

A: Potentially. Enbridge excluded all "sales" projects, related to the connection of new loads, and all replacement and relocation projects. Both of these categories may contain load-related costs. In particular, the sales projects would provide some of the capacity required for new customers, and the size of new mains may be a function of the efficiency of the new customers, and possibly existing customers served by the same lines. Similarly, the size of replacement mains can be affected by load levels, and replacement of a small

[31] Enbridge does not specify what purpose the Ottawa Reinforcement met, other than meeting demand.

old main with a larger-diameter smooth main can increase the capacity of the line.

Alternatively, the increases in capacity associated with sales, replacement and relocation projects can be reflected by adjusted downward the load growth served by the reinforcement projects, as I discuss in the next subsection.

b) Design-peak Load Growth, 2010–2019

Q: Have you been able to review the data on design-day peak growth that Navigant presents in its Figure 4?

A: No. However, even if the data reflect weather-adjusted peaks for 2010 and Enbridge's forecast for 2019 (the intervening loads do not affect the computation), the peak growth should be adjusted down to reflect the part of the growth that is accommodated by sales projects and upgrades of replacement mains. The cost of reinforcements should be divided by the growth requiring the reinforcements, excluding any growth accommodated by other projects. The lower the growth divisor, the higher the ratio of investment per unit of peak load.

For example, the Municipality of York Pipeline Project (EB-2011-0270) replaced an NPS 4 and an NPS 8 line with an NPS 12 main along the same route, more than doubling the capacity of that section of the system. While the replacement was triggered by a relocation request from the municipality, the update would serve any increase of load in that demand area (Whitchurch-Stouffville and Uxbridge). The load increases that drive the need for reinforcements would be net of the load increases in the Whitchurch-Stouffville and Uxbridge areas, and all other areas in which growth was served by sales, replacement and relocation projects.

c) Annualizing the Avoided Distribution Cost

Q: How does Navigant annualize the avoided distribution costs?

A: Navigant uses a nominal 5.9% carrying charge for the distribution investments, which it does not document. In contrast, I estimate a *real-levelized* carrying charge of about 6%. I used a standard computation of the real-levelized or economic carrying charge, which measures the present-value benefits of a one-year delay in the investment, with the benefit rising at inflation in subsequent years.[32] I suspect that Navigant became confused between real and nominal carrying-charge computations.[33] I cannot test that, since Enbridge has not provided Navigant's workpapers.

A 6% real-levelized carrying charge is equivalent to a nominally levelized carrying charge of about 7.7%. The real-levelized discount rate provides meaningful avoided costs for any period, while the nominally levelized carrying charge is only meaningful for the period over which it is levelized. While the benefit of deferring investments rises as the investments are pushed further back (due to inflation), Navigant somehow concludes that avoided distribution costs would fall over time.

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[32]I used the inputs specified by Navigant in its Table 8, a 2% inflation rate, and a 7% discount rate, based on assumptions elsewhere in Enbridge's filing.

[33]It is possible that Navigant intended that its carrying charge be applied in real terms, but accidentally treated the charge as nominal.

d) Converting from Peak Day to Normal Average Usage

Q: Did Navigant properly apply the load data to convert the avoided T&D in annual dollars per cubic metre on the design day to dollars per cubic metre of annual consumption for each load shape?

A: Navigant did not provide the design-day peak, normal-year peak, annual consumption, or any other data on the load shapes they used. However, Navigant describes the data it used as follows:

> calculated avoided cost in terms of annual DSM volumes saved instead of peak day demand gas savings. This is done by using Enbridge's existing DSM load shape profiles using the peak day demand to annual volume ratio. (Enbridge Exhibit C, Tab 1, Schedule 4, at 6)

> Daily gas consumption for each load shape is gathered. The total annual consumption for the year is calculated and the gas consumption for the peak day demand (January 15) is determined. The consumption for the peak day demand is divided by the total annual consumption. The ratio for each of the four DSM load shapes is used to convert the peak day demand distribution avoided cost ($\$/10^3m^3$ annual peak day demand) to a volumetric avoided cost. (Ibid. at 26–27)

Appendix B to the Navigant study shows graphs of the load shapes that Navigant used. While it is not entirely clear, these seem to be normal load shapes, without any allowance for design conditions.

Q: What is the significance of using normal peak loads instead of design peak?

A: Since design peak is higher than normal peak, each thousand m^3 of annual savings results in greater savings on the design peak than on the normal peak. The distribution system is designed for the design-peak day (or the design-peak hour), while DSM savings are computed for the average year, so the avoided distribution costs should reflect the ratio of design peak to normal average usage.

e) Operating and Maintenance Costs

Q: Are any avoided O&M costs reflected in Enbridge's estimate of avoided distribution costs?

A: No. Navigant's report (Exhibit C, Tab 1, Schedule 4) assumes that no distribution O&M costs are avoidable.[34]

Q: Is this a reasonable assumption?

A: No. Enbridge's GTA application, for example, reports an incremental O&M of over $13 million for such costs as "leak survey, damage prevention, cathodic protection, [and] direct maintenance." (EB-2012-0451 Exhibit E Tab 1 Schedule 1, at 2, updated: 2013-06-03) That is 1.5% to 2% of the project cost (depending on the costs included in the analysis); those costs would increase over time with inflation.

In its third workshop presentation, Navigant corrected its earlier methodology by (among other things), adding avoided annual O&M of 1% of the avoided investment (EB-2015-0049, Exhibit JT1.23, Attachment 3, at 6).

Since the real-levelized carrying charge for distribution is only about 6%, O&M of 1%–2% would add something like 20% to 30% to the carrying charges for the distribution projects.

[34]In Exhibit I.T9.EGDI.GEC.59(b), Enbridge claimed that reductions in O&M for avoided reinforcements should be ignored because its O&M budgeting process does not consider the effect of reinforcements installed or deferred. This claim does not justify omitting O&M from avoided cost for two reasons. First, since O&M costs do vary with the amount of distribution, the effect of deferrals will eventually appear in the O&M budget. Second, avoided cost should reflect actual costs, not budgets. Budgets should be viewed only as a source of estimates of actual costs.

f) Summary of Enbridge Corrections

Q: What is the cumulative effect of correcting Enbridge's apparent understatements in its estimate of avoided distribution costs?

A: In Table 8, I combine rough estimates for the effects of the errors I discuss above. Specifically, I account for the following:

- the projects that Enbridge acknowledges having failed to share with Navigant,
- the unexplained downward revisions in 2010–2012 additions,
- the full estimated costs of Segment B2 of the GTA,
- the cost of Segment B1 of the GTA (as a sensitivity),
- a 20% reduction in load growth associated with the reinforcements, to reflect the capacity upgrades from sales-related, replacement, and GTA projects. For the sensitivity in which Segment B1 is treated as directly load-related, I use a 10% adjustment for load growth met by the other categories.
- correction of the nominal carrying charge to 7.7% (equivalent to a 6% real carrying charge),
- An allowance for O&M of 1% of investment.

I do not have enough data to correct the load-shape ratios, from normal weather to design weather.

Table 8: Corrections to the Enbridge Estimate of Avoided Distribution Cost

	10-yr Additions 2015$ M	10-yr Growth 103m3	Additions per Unit Growth $/103m3	Carrying Charge Nominal	Annualized $/yr/103m3 peak day	O&M $/yr/103m3 peak day	Total $/yr/103m3 peak day
Enbridge	$189	10,470	$18,052	5.9%	$1,065		$1,065
Corrections							
Area 10	$50.4						
Appendix B	$5.9						
2010-12 revisions	$17.4						
GTA Segment B2	$85	−20%					

GTA Segment B1	$200	−10%					
Corrected							
without B1	$348	8,376	$41,508	7.7%	$3,196	$415	$3,611
with B1	$548	9,423	$58,121	7.7%	$4,475	$581	$5,057

The corrected nominally-levelized values are about 3.4 to 4.7 times the Enbridge estimate. In real-levelized terms, the total costs would be about \$2,900–\$4,100/yr/10^3m^3 of peak-day throughput, or 2.7–3.8 times Enbridge's nominally-levelized estimate in 2015, and would rise with inflation.

Q: Did Navigant develop higher estimates of avoided distribution costs than those presented in Enbridge's filing?

A: Yes. In its second workshop for Enbridge, Navigant reported an avoided distribution cost of \$1,165/10^3m^3 savings on the peak day (Exhibit JT1.23, Attachment 2, at 11).[35] In its third workshop presentation, Navigant reported an avoided distribution cost of \$1,523/10^3m^3 savings on the peak day (Exhibit JT1.23, Attachment 3, at 6). These values are about 10% and 40% higher than the \$1,065/10^3m^3 reported by Navigant in Exhibit C, Tab 1, Schedule 4 and apparently used by Enbridge in screening DSM programs.

2. Union

Q: How did Union estimate its avoided distribution costs?

A: Union did not develop T&D avoided costs based on its own system, but borrowed the work from Navigant based on Enbridge's system and adapted them for its use. Specifically, Union took the Enbridge estimates of avoided distribution costs by load shape, weighted those values by the share of Union's estimated DSM savings in 2015 for each of the load shapes, and

[35] Navigant does not appear to have used design-day loads in its analyses.

Exhibit L.GEC.1

Before the Ontario Energy Board

EB-2015-0029 and EB-2015-0049

Union and Enbridge 2015-2020 DSM Plans

Prepared by:

Chris Neme
Energy Futures Group

For:
The Green Energy Coalition
David Suzuki Foundation
Greenpeace Canada
Sierra Club of Canada

July 29, 2015
Corrected August 12, 2015

II. Testimony Summary

My analysis of both the evidence presented by Enbridge and Union in their 2015-2020 DSM plans, as well as analysis of relevant data and information from other jurisdictions, leads me to a number of key conclusions. Those conclusions are presented in this section. More detailed analysis supporting the conclusions is provided in ensuing sections.

1. Savings Targets and Budgets (Issues 2 and 3)

A. **Both utilities' proposed savings goals are inconsistent with the province's "conservation first" policy**. Both companies have proposed savings levels over the 2016-2020 period that are a little more than half of what leading jurisdictions have already achieved.[5] Though Enbridge's proposed savings are higher than their programs have achieved in recent years, Union's are dramatically lower, with the result being that annual savings province-wide will actually be lower in every year from 2016 to 2020 than they were in every year from 2012 to 2014. Both utilities are also continuing to forecast extremely low participation rates for a number of key efficiency technologies and programs.

At a high level, there are four factors that underpin the utilities' low savings targets:

a. **Budget constraints –** both utilities limit their DSM budgets to the levels suggested in the Board's recent gas DSM framework and guidelines;
b. **Union's cancelling of its large industrial program –** Union followed the framework's/guidelines' suggestion to stop offering its self-direct program;
c. **Greater emphasis on smaller customers –** both utilities propose placing greater emphasis on treating efficiency opportunities from residential and smaller business customers, from which savings are typically more expensive to acquire (though still cost-effective); and
d. **Conservative savings estimates –** both utilities appear to have used conservative assumptions regarding the savings yields from some of their proposed programs.

B. **The utilities should have higher budgets to acquire greater savings.** The utilities argue that their budgets are appropriate because they follow the Board's guidelines to limit spending to the equivalent of approximately $2 per month per residential customer. There are several problems with that argument:

a. **New Provincial policy commitments to carbon emission reductions should render 2014 budget guidance obsolete.** The policy landscape has changed since

[5] Note that throughout this evidence I often refer to annual savings rather than the lifetime savings that are the focus of the utilities' performance metrics. That is done simply to make comparisons across jurisdictions possible, as many jurisdictions do not report lifetime savings. Lifetimes savings is a better metric of performance and should still be the basis for assessments of utility performance.

December 2014, the month that the Board's framework/guidelines were completed. In particular, the province of Ontario has made several critically important commitments to reducing carbon emissions and addressing climate change. That includes joining Quebec, British Columbia, California, and other sub-national jurisdictions in re-affirming a commitment to at least an 80% carbon emission reduction by 2050;[6,7] the establishment of a new commitment to a 37% carbon emission reduction in the province by 2030;[8] and the commitment to imposing a carbon "cap-and-trade" policy to meeting those requirements.[9] The cost of carbon emission reductions will be borne by all customers, including DSM non-participants. Thus, if carbon emission reductions from efficiency are constrained by a $2 per month spending cap, gas customers (including non-participants in DSM programs) will have to pay for more carbon emission allowances and/or for other (likely more expensive) approaches to reducing emissions.

b. **Even if $2 per month per non-participating residential customers were an appropriate limit for the impact of gas DSM, the limit should be expressed as $2 per month *net of both DSM spending and DSM benefits to non-participants*.** Gas DSM produces several system-wide benefits – including reduced capital expenditures on transmission and distribution, commodity price suppression effects, the ability to purchase less of the more expensive gas and reduced carbon regulation compliance costs – that put offsetting downward pressure on rates. Thus, even if it were appropriate to cap the level of DSM spending in order to limit the impact on the average non-participating residential customer to $2 per month, the cap should be set such that the impact on non-participants is $2 per month from the *combined effects* of DSM spending and system-wide benefits. Mr. Chernick's analysis suggests that, in aggregate, the magnitude of the system-wide benefits for the utilities' proposed DSM plans is equal to 1½ times (or more) the size of the budgets in those plans. Put another way, the combined effect on rates of both the DSM spending and the system-wide benefits from the utilities proposed plans should be a *reduction* of more than $1 per month over the over the life of the efficiency measures funded. Clearly, significant additional DSM spending – which will produce additional system-wide benefits – could be pursued without crossing a $2 per month *net* rate impact on consumers.

c. **OEB Guidelines are not requirements.** Indeed, the utilities' proposed plans

[6] California, Ontario, Quebec, British Columbia, "Joint Statement on Climate Change", December 2014 (see: http://www.ontario.ca/document/joint-statement-climate-change?_ga=1.184104870.1411524858.1437404779)
[7] SustainableBusiness.com News, "Under 2 MOU signed by 12 Governments", 05/20/2015 (see: http://www.sustainablebusiness.com/index.cfm/go/news.display/id/26305)
[8] Ontario Ministry of the Environment and Climate Change, "Ontario First Province in Canada to Set 2030 Greenhouse Gas Pollution Reduction Target", May 14, 2015 press release (http://news.ontario.ca/ene/en/2015/05/ontario-first-province-in-canada-to-set-2030-greenhouse-gas-pollution-reduction-target.html)
[9] Office of the Ontario Premier, "Cap and Trade System to Limit Greenhouse Gas Pollution in Ontario", April 3, 2015 press release. (see: http://news.ontario.ca/opo/en/2015/04/cap-and-trade-system-to-limit-greenhouse-gas-pollution-in-ontario.html)

III. Benchmarking Utilities' Savings Targets

1. Overview of the Utilities' Proposed Savings Levels

Consistent with the Board's new gas DSM framework and guidelines, both Enbridge's and Union's plans for 2015 are essentially "roll-overs" of their 2014 plans. Both utilities propose substantial increases in DSM spending in 2016 with much more modest increases in subsequent years. The average proposed spending levels over the 2016-2020 period are 3% to 5% below the annual spending levels suggested in the Board's DSM framework (i.e. $75 million per year for Enbridge and $60 million per year for Union, excluding shareholder incentives). In Enbridge's case, spending roughly 2½ times more in 2020 than in 2014 is forecast to produce an 81% increase in incremental annual savings and a 64% increase in lifetime savings. In Union's case, a near doubling of spending from 2014 to 2020 is forecast to result in a 40% to 50% *reduction* in both incremental annual savings and lifetime savings. The net impact for the province as a whole is a net reduction in both incremental annual savings (a little more than 10% less in 2020 than in 2014) and lifetime energy savings (nearly 20% less from the 2020 spending than was achieved in 2014).

Put simply, the utilities' proposed savings targets are not even close to being consistent with the notion of a "conservation first" policy. The following subsections discuss a number of benchmarks that support those conclusions.

2. Savings Will Be Well Below Leading Jurisdictions

The incremental annual savings forecast by Ontario's utilities equates to approximately 0.6% (Union) to 0.7% (Enbridge) of annual sales to customers other than electric generators over the 2016-2020 period.[12] As Figure 1 shows, that level of savings is a little more than half of what of what leading jurisdictions have already achieved (i.e. in 2014)."[13] Like the Ontario utilities, utilities in these jurisdictions all have both cold winter climates and very long histories of running gas efficiency programs.

[12] I focus in this section on savings from and sales to customers other than electric power generators to facilitate "apples to apples" comparisons between utilities. When one includes sales to electric power generators, Union's projected incremental annual savings as a percent of sales is only 0.5%.

[13] I focus on this five year period in their plans because we are already well into 2015, and the Board essentially required a continuation of past programs this year, so it really cannot be considered anything other than a "bridge year" to a new plan.

4. Key Reasons for Low Forecast Savings

At a high level, there are four factors that appear to drive the utilities' relatively low savings targets:

1. **Budget constraints –** both utilities' limit their DSM budgets to the levels suggested in the Board's recent gas DSM framework and guidelines;
2. **Union's cancelling of its large industrial program –** Union followed the framework's/guidelines' suggestion to stop offering its self-direct program;
3. **Greater emphasis on smaller customers –** both utilities' propose placing greater emphasis on treating efficiency opportunities from residential and smaller business customers, from which savings are typically more expensive to acquire (though still cost-effective); and
4. **Conservative savings estimates –** both utilities appear to use conservative assumptions regarding the savings yields from some of their proposed programs.

Each of these are discussed in more detail below.

IV. Utility Budget Proposals

1. Benchmarking 2016-2020 Ontario Gas DSM Budgets

As noted above, both Enbridge and Union have proposed budgets for the 2016-2020 period that are consistent with the Board's December 2014 gas DSM framework and filing guidelines which suggested that budgets be capped at approximately $2 per month per residential customer (and the equivalent for business customers). The result is proposed spending levels that are low compared to leading jurisdictions.

Consider, for example, the American Council for an Energy Efficient Economy's (ACEEE's) most recent state efficiency scorecard.[25] Among other indicators, the scorecard ranks states by the size of their gas efficiency program budgets. The metric that they use is spending per residential customer. The top 8 states in 2013 – those to which ACEEE gave its highest score on this metric – spent an average of $91 CDN per residential customer.[26] That is more than double what both Enbridge ($35) and Union ($41) are forecasting they will spend per residential customer (in 2015 dollars) over the 2016-2020 period. Even the lowest spending of those eight leading states (New York) was spending about 80% more in 2013 than the average the Ontario utilities have collectively proposed to spend annually over the 2016-2020 period. Put another way, Enbridge's and Union's proposed average spending levels for 2016-2020 would have put them in ACEEE's 3rd tier of states in 2013.[27]

2. Implications of Ontario Climate Policy for DSM Budgets

In 2007, the Ontario government adopted the following set of greenhouse gas emission reductions targets:

- 6% reduction below 1990 levels by 2014;
- 15% reduction below 1990 levels by 2020; and
- 80% reduction below 1990 levels by 2050.[28]

In subsequent years, additional climate policies, including the "conservation first" policy, were adopted. More recently additional significant policy commitments have been made. For example, the province recently joined Quebec, British Columbia, California, and other sub-national jurisdictions in re-affirming a commitment to at least an 80% carbon emission reduction by 2050.[29,30] In the Spring of 2015 it also established a new commitment to a

[25] Gilleo, Annie et al., "The 2014 State Energy Efficiency Scorecard", ACEEE Report Number U1408, October 2014.

[26] The average was $68.51 in 2013 U.S. dollars. That value is escalated by 2.4% to convert to 2015 USD and then by 30.3% to convert to 2015 Canadian dollars.

[27] There are only five tiers, and the fifth tier is essentially for the states that are not doing anything with gas DSM.

[28] Ontario Ministry of the Environment and Climate Change, "Ontario's Climate Change Update 2014", p. 4.

[29] California, Ontario, Quebec, British Columbia, "Joint Statement on Climate Change", December 2014 (see: http://www.ontario.ca/document/joint-statement-climate-change?_ga=1.184104870.1411524858.1437404779)

[30] SustainableBusiness.com News, "Under 2 MOU signed by 12 Governments", 05/20/2015 (see:

37% carbon emission reduction in the province by 2030[31] and committed to imposing a carbon "cap-and-trade" policy to meet those requirements.[32]

These policy decisions, including the most recent commitments made just several months ago, raise questions about whether the OEB's 2014 gas DSM budget guidelines are outdated. Though the province was expected to meet its 2014 target, it is currently expected to fall about 30% (about 19 megatonnes) short of the emission reductions required to meet its 2020 target.[33,34] Absent new policies or programs (i.e. with the current Climate Change Action Plan as the baseline), the province is currently projected to see its emissions gradually increase back to 1990 levels.[35] Thus, the province will need much greater reductions – on the order of 67 megatonnes – to meet its new 2030 target. That translates to about 4.5 megatonnes reduction per year, which is on the order of 2.5% annually, for each of the next 15 years. Natural gas accounts for approximately 30% of all greenhouse gas emissions in the province, so some portion of the additional future emission reductions will almost certainly have to come from the natural gas sector.

Given the seriousness and aggressiveness of the Province's greenhouse gas emission reduction commitments, one could argue that investment in gas efficiency programs should be constrained only by the cost-effectiveness of such programs (rather than by any arbitrary spending limits). While it is the role of government to develop a carbon emission reduction plan for Ontario, including allocation of reductions across sectors, it is clear that maximizing reductions that have no net cost or even substantial net economic benefits (cost-effective conservation) before investing in more expensive options will minimize the Provincial cost of carbon emission control.

It should also be recognized that any constraints on DSM spending – and by extension, constraints on how much cost-effective energy savings will be acquired – impose additional costs on gas ratepayers in the form of either additional greenhouse gas emission allowances that must be purchased and/or additional costs to reduce emissions through other means. Mr. Chernick's preliminary estimates are that the value of carbon allowances can be expected to be on the order of $20 USD per ton per year at the start of a carbon cap and trade system, and increase to more than double that amount by the end of a an average gas efficiency measure's 15 to 20 year life. Based on those estimates, the net present value of an m^3 of annual gas savings that lasts 16 years (a typical average measure life) is close to $1. Both Enbridge and Union are projecting that their filed plans will achieve average incremental annual savings of about 75 million m^3 over the 2016-2020 period. Thus, the

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http://www.sustainablebusiness.com/index.cfm/go/news.display/id/26305)

[31] Ontario Ministry of the Environment and Climate Change, "Ontario First Province in Canada to Set 2030 Greenhouse Gas Pollution Reduction Target", May 14, 2015 press release (http://news.ontario.ca/ene/en/2015/05/ontario-first-province-in-canada-to-set-2030-greenhouse-gas-pollution-reduction-target.html)

[32] Office of the Ontario Premier, "Cap and Trade System to Limit Greenhouse Gas Pollution in Ontario", April 3, 2015 press release. (see: http://news.ontario.ca/opo/en/2015/04/cap-and-trade-system-to-limit-greenhouse-gas-pollution-in-ontario.html)

[33] Ontario Ministry of the Environment and Climate Change, "Ontario's Climate Change Update 2014", p. 4.

[34] Environmental Commissioner of Ontario, "Feeling the heat: Greenhouse Gas Progress Report 2015", July 2015.

[35] Ontario Ministry of the Environment and Climate Change, "Ontario's Climate Change Update 2014", p. 16.

value of avoided carbon emissions would be enough to roughly offset the entire Enbridge DSM budget and to more than offset the entire Union DSM budget. As discussed further below, those are benefits that accrue to all gas ratepayers, including non-participants, once a carbon cap-and-trade regulation is put in place in Ontario.

3. Implications of System-Wide Benefits of Efficiency for DSM Budgets

In establishing its DSM budget guideline as the equivalent of $2 per month per residential customer, the OEB appeared to be attempting to put a limit on the adverse effects that DSM spending would have on non-participants in efficiency programs. However, it also appears that in setting that guideline the Board did not have before it evidence on the magnitude of offsetting benefits that put downward pressure on rates. As Mr. Chernick's evidence demonstrates, there are at least four categories of such benefits:

1. Reductions in the cost of complying with greenhouse gas emission regulations (discussed above);
2. Commodity price suppression effects;
3. Reduced purchases of higher priced gas (a by-product of the fact that the marginal price of gas is higher than the average price reflected in rates); and
4. Avoided capital investment in distribution system infrastructure.

The value of these system-wide benefits, expressed in lifecycle net present value terms per annual m^3 saved, are provided in Table 3 below.

Table 3: Efficiency Benefits that Put Downward Pressure on Rates

Benefit	NPV of Lifetime Benefits per Annual m^3 Saved[36]		Average Annual Value from Utilities'2016-2020 DSM Plans (millions $)[37]		Benefits as a % of Average Annual (2016-2020) DSM Plan Budget[38]	
	Enbridge	**Union**	**Enbridge**	**Union**	**Enbridge**	**Union**
1 Avoided carbon regulation costs[39]	$0.98	$0.98	$73.2	$73.9	101%	129%
2 Price suppression effects[40]	$0.08	$0.08	$6.2	$6.3	9%	11%
3 Reduce purchase of most expensive gas[41]	$0.10	$0.18	$7.2	$13.3	10%	23%
4 Avoided distribution system costs[42]	$0.38	$0.24	$28.1	$18.2	39%	32%
Total	**$1.54**	**$1.49**	**$114.7**	**$111.7**	**158%**	**195%**

[36] Assumes an average measure life of 16 years. All values in 2015 Canadian dollars (CDN).
[37] This is NPV of benefits per annual m3 saved multiplied by the average incremental annual m^3 savings forecast for the 2016-2020 period by Enbridge (74.4 million m^3) and Union (75.1 million m^3).
[38] Enbridge's average annual budget is $72.3 million; Union's is $57.4 million (both in 2015 dollars).
[39] Valued at Mr. Chernick's estimate of avoided costs of carbon emission regulations. As noted above, Mr. Chernick suggests such values would start at approximately $20 (2014 USD) per ton of CO_2 or $1.18 USD per MBtu of natural gas in the first year of a regulatory scheme. The values per m^3 of reduction are the same for both Enbridge and Union as the market clearing price unit of emissions is likely to be a provincial price.
[40] Mr. Chernick estimates that a 1 billion m^3 reduction in annual gas demand would produce a $0.00027 reduction in price per m^3. Over the 2016-2020 period, I assume that average annual gas sales in Ontario will be approximately 27 billion m^3. Thus, the price reduction benefit to Ontario gas users from a 1 billion m^3 reduction in gas demand would be worth approximately $7.2 million. That equates to a benefit of approximately $0.0072 for one year's worth of a single m^3 of demand reduction. That, in turn translates to a benefit of approximately $0.083 for 16 years (the average measure life) of one m^3 of demand reduction. The magnitude of this benefit is assumed to be the same (per m^3 of savings) for both utilities.
[41] For Enbridge, Mr. Chernick estimates that this benefit is equal to approximately $0.013 per m^3 of space heating gas saved per year and $0.011 per m^3 of combined space heating and water heating energy saved per year; there are essentially no such savings from baseload measures (industrial and water heating). For Union, I used the average of the differences Mr. Chernick reports for 2015 and 2016 (Chernick p. 28): $0.015 for baseload and $0.017 for space heating measures. Data on the mix of end use gas saved in the utilities' proposed plans were not included in their filing. Thus, I have assumed that the mix (in percentage terms) will be the same as in 2014 for Enbridge and the same as in 2014 for Union excluding the T2/Rate 100 savings. To the extent that the utilities will get more of their savings in future years from space heating these estimated benefits will be conservatively low."
[42] Enbridge used estimates of avoided distribution system costs developed for the Company by Navigant Consulting (Exh. C/T1/S4). The magnitude of those avoided costs varied by a factor of 4, depending on whether the savings were from space heating or from baseload measure end uses like water heating or industrial process efficiency improvements (See Navigant Table 7). Mr. Chernick has found that Enbridge's avoided distribution costs are actually three to five times higher than Navigant estimated for the Company. I have used the mid-point (factor of four) of that range. In this case, I estimated the lifetime NPV of an annual savings of an m^3 using a nominal discount rate (i.e. the 4% real discount rate adjusted for an assumed annual inflation rate of 1.68%) because Navigant estimates were expressed in constant nominal dollars. A weighted average value for the entire Enbridge portfolio was estimated based on the Company's 2014 distribution of savings by end use. Absent better information, the values for Union were assumed to be the same as for Enbridge per end use. However, because Union's savings are assumed to be more baseload heavy and less space heating focused, the weighted average value per m^3 is estimated to be lower for Union.

As Table 3 shows, under the utilities filed plans, the system-wide benefits that accrue to all gas ratepayers, participants and non-participants alike, are more than one and a half times greater than the magnitude of the DSM budgets necessary to produce them. Put another way, the combined effects on rates of *both* DSM budgets *and* the system-wide benefits they produce (under the spending and savings levels the Companies have proposed) would be more than a $1 per month *reduction* over the life of the efficiency measures installed. Thus, if the Board were to determine that a rate impact of $2 per month is still as large as it was comfortable accepting, there is clearly much more room for increase in DSM spending and savings before that level is reached.

savings by a factor of 2½. Roughly two-thirds of that increase would come from just continuing its large industrial self-direct program.

To be sure, such increased levels of savings would require increased budgets. My very preliminary estimate – based on the experience of leading jurisdictions, the Ontario utilities' own past history and the nature of some emerging opportunities for acquiring savings – is that budgets would likely need to increase by a factor of 2 to 2½ (i.e. to on the order of $150 to $200 million per year for Enbridge and $125 to $150 million for Union per year). However, it is important to recognize that while leading jurisdictions are all achieving very similar levels of savings, the costs that they are experiencing to acquire those savings vary quite considerably,[61] suggesting that it would be difficult to definitively extrapolate their costs to Ontario. Put another way, to estimate with confidence how much the Ontario gas DSM budgets would have to increase to achieve leading levels of savings would require a bottoms up, program-by-program assessment of how the additional savings would be achieved. Such an assessment would need to address the extent to which different programs could be expanded; the potential impacts of changing program designs (e.g. moving to upstream incentives); the impacts of increasing incentive levels – including not only increased participation and incentive costs but also the likelihood of lower free rider rates; and the degree to which fixed costs of administering programs would be spread over a larger volume of savings. That kind of analysis was beyond my ability to perform for this proceeding given time and resource constraints, as well as the wide range of issues to address.

Similarly, to definitely estimate the increase in net economic benefits that would accrue from the kind of much more aggressive DSM portfolio savings levels that I suggest above would require a program-by-program build-up of how the additional savings would be derived. That said, there is every reason to believe that the additional net economic benefits would be substantial.

For example, Enbridge has estimated that its program plan would generate an average of about $225 million in TRC benefits per year over the 2016-2020 period at an average annual TRC cost of about $95 million for an average annual TRC net benefit of about $130 million.[62] If its savings increased by 80%, the increase was roughly proportionally the same across all its programs,[63] and non-incentive costs per m^3 saved did not change (probably a conservative assumption),[64] the additional savings would generate approximately $105 million per year (roughly $525 million over the 2016-2020 time period) in additional net economic benefits when using Enbridge's estimates of avoided costs.[65] As Mr. Chernick

same range (between 40% and 50% in 2012 per its response to GEC.1).

[61] Their costs per unit of savings vary from a little lower costs than those proposed in the Ontario utilities' plans in Minnesota to roughly triple those proposed in the Ontario utilities' plans in Massachusetts.

[62] Exh B/T2/S3 corrected.

[63] This purely a simplifying assumption for the sake of this preliminary calculation. As noted above, a more aggressive program portfolio should be developed in a systematic way, with priority placed on programs that meet strategic objectives such as maximizing savings while addressing customer equity concerns.

[64] As noted above, one should expect administration costs to decline per unit of savings.

[65] It is important to remember that most of the increase in budget associated with the more aggressive efficiency program portfolio I have suggested would be associated with increased financial incentives for efficiency measures and/or projects. Increased incentives simply offset customer contributions to measures

notes, Enbridge's estimates of avoided costs are too low, so the additional net economic benefit of a more aggressive DSM portfolio could be even greater than these values suggest.

Union has estimated that the TRC net benefits from its 2015-2020 DSM plan are approximately $1 billion, or approximately $170 million per year. Thus, if it were to increase its savings over that time period by a factor of 2½ the additional net economic benefit could be on the order of an additional $250 million per year. Again, one would need to develop a detailed program-by-program build-up of the new savings target to develop more precise estimates of additional net benefits. However, since the majority of the increase in savings I would expect from Union would come from T2/R100 customers, which have historically provided the most cost-effective savings in Union's portfolio, it is possible if not likely that the estimate of additional net benefits for Union are even greater than my simple extrapolation suggests. It is also important to note that Mr. Chernick is suggesting that Union's estimates of avoided costs are too low. That also suggests that the rough estimate of additional net benefits may be too low.

costs under the TRC test, so it is only budgetary increases in non-incentive costs that can adversely affect TRC – and therefore societal – net benefits.

VI. Union's Large Industrial Customers

As noted above, Union Gas' proposed annual savings targets for 2016 to 2020 period are on the order of about half of what they achieved annually from 2012 to 2014, despite a near doubling of its DSM budget. Put another way, its forecast savings yield per budget dollar is more than 70% lower in its proposed plan than what it achieved annually from 2012 through 2014. The single biggest reason for this decline is Union's decision to terminate (after 2015) its large industrial self-direct program. That program accounted for roughly half of Union's total 2013 and 2014 savings – *even after adjusting for an assumed free rider rate of 54%*. Union's decision to terminate the program appears to have been based on the OEB's guidance in its December 2014 gas DSM framework.

In its framework and guidelines, the Board articulated two reasons for not requiring the large industrial customers to participate in funding efficiency programs: (1) that there are concerns about "one customer subsidizing business improvements of another";[66] and (2) that the large customers were both sufficiently sophisticated and motivated to invest in efficiency on their own. However, the Board's guidelines were developed under considerable time pressure and without the advantage of a full testing of concerns in an evidentiary proceeding.

It should be noted that the Self Direct program model that Union adopted for its largest customers starting in 2013 already effectively eliminated the Board's first concern about cross-participant subsidies by effectively setting aside the majority of DSM budget generated by each customer specifically for their individual use.[67]

There is also no empirical evidence, from Ontario or any other jurisdiction, to support the hypothesis underlying the Board's second concern – that large customers would pursue all cost-effective efficiency investments on their own. While it is true that there will be free ridership in programs offered to large customers, that is true to varying degrees for all programs. Moreover, the savings that Union has claimed from this program are already discounted by 54% to account for an estimate of free ridership. The remaining 46% of savings that the utility claimed still represented roughly half the savings it produced from its entire portfolio of efficiency programs in 2013 and 2014, suggesting that there are enormous cost-effective[68] savings that their large customers would not be pursuing on their own.

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[66] OEB DSM Framework, p. 27.

[67] The remaining funds were allocations to cover Union's costs of managing and evaluating the program and to contribute to low income efficiency program offerings. There was also the potential for the utility to earn a shareholder incentive for meeting or exceeding its goals.

[68] Benefit-cost ratios were 8.74 to 1 in 2013 and 4.8 to 1 in 2014 (see B.T6.Union.GEC.4 Excel Attachment 2 – 2013 Audit tool 20150623 and B.T6.Union.GEC.4 Excel Attachment 3 – 2014 Audit Tool 20150623)

While Union's estimate of free ridership is admittedly based on an outdated study, its implicit conclusion that there are substantial cost-effective savings that large customers would not pursue absent efficiency programs is consistent with assessments from other jurisdictions. For example, a recent jurisdictional scan conducted by Navigant Consulting for the Ontario gas Technical Evaluation Committee found that the average free rider rate from evaluations of twenty-four different gas utility Custom C&I programs – which are typically targeted to the largest customers – was between 30% and 40% (meaning 60% to 70% of savings would not have occurred without the utility programs).[69]

ACEEE reached a similar though more qualitative conclusion in its 2012 report on Self Direct programs for large industrial customers:

> *"Another assumption frequently made during the development of opt-out and self-direct programs is that industrial customers will always do all cost-effective energy efficiency because doing so makes good business sense…While industrial firms in the U.S. have continued to become more energy efficient per unit of product output, they have not necessarily captured all cost-effective energy efficiency. Again, opt-out and self-direct programs have proven this to be true. In Utah, Wyoming and Oregon, customers can opt out of all or part of their CRM (cost-recovery mechanism) fees if they can prove that they have in fact done all cost-effective energy efficiency. In the case of Utah and Wyoming, "cost-effective" means that a project has a simple payback of eight years or less; in Oregon it is ten years. To date, no company has taken advantage of these exemptions in any of these states, because there are always some cost-effective projects that could be identified during an energy audit (Helmers 2011, Stipe 2011)."*[70]

In EB-2012-0337, after the OEB heard evidence from APPrO and others, the Board itself came to a similar conclusion when it stated that industrial DSM programs "have shown to be efficient and to have societal benefits with respect to reducing greenhouse gas emissions and encouraging wiser energy usage."

That conclusion is born out again by a recent evaluation of free ridership and net-to-gross (NTG) ratio for Utah's large customer self-direct program. It concluded that free ridership was only 1% and that spillover effects were 5%, leading to an NTG of 1.04.[71]

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[69] Brannan, Debbie et al. (Navigant), "Custom Free Ridership and Participant Spillover Jurisdictional Review", prepared for Sub-Committee of the Ontario Technical Evaluation Committee, May 29, 2013. (http://www.ontarioenergyboard.ca/documents/TEC/Evaluation%20Studies%20and%20Other%20Reports/Ontario%20NTG%20Jurisdictional%20Review%20-%20Final%20Report.pdf)

[70] Chittum, Anna, "Follow the Leaders: Improving Large Customer Self-Direct Programs", ACEEE Report Number IE112, October 2011.

[71] Navigant Consulting and EMI Consulting, "Evaluation Report for Utah's Self-Direction Credit Program (PY

It should also be noted that virtually all of Union's eligible large industrial customers are participating in its Self-Direct program. Indeed, 95% of eligible customers representing 99% of throughput of eligible customers participated in the program in just 2014.[72] That information, which was also not available to the Board when it developed its December 2014 guidelines, should address concerns about rate impacts on non-participants. Moreover, because the utility cost of acquiring the savings from these large customers is so much less than the cost of acquiring savings from smaller customers, the net impacts on rates for the affected large industrial customers – from the combined effects of DSM spending and the system-wide benefits described above – appears to be much better than for the average residential or small business customer. And because the rate reducing impacts from price suppression, reduced purchases of expensive gas, reduced investment in T&D and reduced GHG mitigation costs are shared among customer groups, the cancellation of this program would harm all customers.

Put simply, allowing Union to terminate its large industrial program would mean foregoing a huge portion of achievable savings and – because these savings tend to be more cost-effective than those that can be acquired from other, smaller customers – an even larger portion of economic benefits.

All that is not to say that the self-direct program cannot be improved. At a high level, there are at least three things the Board could require in the way of program changes that could improve its effectiveness in delivering savings, addressing customer needs, reducing free ridership and/or addressing concerns of the likely very few customers who believe that they have already pursued all cost-effective efficiency:

1. **Allow self-direct funds to be spent over a multi-year period**. As noted in my testimony in EB-2012-0337, that would give customers much greater flexibility.
2. **Limit the range of measures the self-direct program could fund**. For example, the program could impose a minimum payback of 1.5 or 2 years, particularly (or perhaps exclusively) for operational improvements. That is an imperfect instrument for addressing free ridership concerns because many customers have measures with very short paybacks that they do not pursue without DSM program support. Nevertheless, on average, it would likely reduce free rider rates and could avoid contentious savings claims.
3. **Include an opt-out or payback option for those customers that can truly demonstrate that they have already comprehensively addressed all cost-**

2012 through 2013), prepared for Rocky Mountain Power (a division of Pacificorp), March 18, 2015.
[72] Union response to GEC.54.

effective efficiency opportunities. For example, the customer could opt out of the program if an independently hired auditor can demonstrate that all efficiency measures with less than a 10 year payback have already been implemented. As noted above, this approach has been used in a couple of other jurisdictions. If an "opt out" is deemed to be procedurally problematic because of concerns about treating different customers in the same rate class differently (as the Board noted in its EB-2012-0337 Decision), it may be possible to adopt an alternative that achieves the same end, such as a payback mechanism.

VII. Shareholder Incentive Mechanisms and Metrics

1. Enbridge

A. Resource Acquisition

Enbridge has proposed separate lifetime savings metrics for large customers and smaller customers, as well as for numbers of home retrofit participants. Given its intention to shift greater attention to smaller customers that have historically not participated as substantially in its programs, it seems appropriate to have such metrics. However, given that savings per dollar that it is forecasting for large C&I customers is three times as great as for small C&I customers and six times as great as for residential customers, there is potential for the Company to "game" the system by shifting resources from the more expensive smaller customers to larger customers once the plan is approved. Thus, it may be appropriate to consider whether the metric for larger C&I customers should be part of a separate scorecard.

An alternative would be to refine the way that scorecard scores are calculated. Specifically, if a performance metric has a weight of 40%, the score for that metric could be capped at 60% (i.e. 150% of the target level). That mitigates the "gaming" risk discussed above. It also mitigates the risk associated with a metric that is inadvertently set far too low, as has clearly been done on occasion in the past.[73]

With respect to the specific proposed metric values, Enbridge's proposal for large C&I customers appears consistent with its historic experience in terms of savings per budget dollar (in real, inflation adjusted, terms).[74] The same is true of the home retrofit program savings forecast.[75]

However, the cost per unit of lifetime savings that the Company is forecasting for its small C&I customers is more than three times what it achieved in the past.[76] A big part of the reason is the launch of its Direct Install program, which is always a more expensive way to generate savings but which is also widely viewed in the industry as a necessary vehicle for addressing many smaller businesses that would otherwise not participate in DSM programs. Enbridge's cost per lifetime m^3 saved from its proposed program (a little more than $0.08) appears to be roughly 20% greater than what other gas utilities are paying for small business direct install savings.[77] That difference could be a function of the mix of measures included

[73] Consider, for example, Enbridge's 2014 resource acquisition scorecard. The utility achieved only 67% of its lifetime savings target, falling well below even the lower bound of performance for a metric that was assigned 92% of the scorecard weight. The other metric in the scorecard – participation in its home retrofit program – was assigned the other 8% of the weight. However, because the Company exceeded the home retrofit participation target by a factor of more than 12 (i.e. it achieved more than 1300% of the goal), its overall scorecard score was 138%. Put another way, even though its home retrofit program participation metric was assigned only an 8% weight, its result for that program alone produced 106% of the total 138% scorecard score (the other 32% of the score came from the lifetime savings results).
[74] JT1.36 Attachment 1.
[75] JT1.36 Attachment 1.
[76] JT1.36 Attachment 1.
[77] This conclusion is based on a search for actual results for gas small business direct install programs on E-

Moreover, even some of the questions that Union indicates the study will be designed to address are problematic as currently framed. For example, it makes no sense to generically ask the question "What is the required load reduction that would lead to deferral of infrastructure?" The answer to that question will necessarily be specific to each infrastructure project. The same is true of the question "Could DSM programs be designed and implemented to achieve the necessary impact?" Put simply, Union has either invested little effort in attempting to address this issue or it is being intentionally vague about its intentions. Either way, the Company may be sending a disconcerting signal that it is not likely to be serious about even-handedly considering DSM as a potential alternative to more expensive infrastructure investments.

In contrast, and to its credit, Enbridge has fully developed and presented a preliminary scope of work for its study. That said, I do have some concerns about that proposed work scope. Specifically, in the third part of the work scope – what Enbridge calls "Intersection #3: Targeted DSM and Reinforcement Projects" – the Company asks some of the same kinds of generic questions that critiqued Union for asking. Examples include:

- "Is it technical feasible?"
- "Is it possible?"
- "Is it cost-effective"

Unlike Union, and again to its credit, Enbridge has indicated in its scope of work that it intends to address these questions through analysis of specific case studies. That addresses the concern I expressed about Union's approach because the questions are not being asked generically. However, it raises an entirely different set of issues regarding how the case study examples will be selected. As I have noted in two different reports I have written on the electric utility experience with using geographically-targeted DSM to defer T&D investments,[89] DSM cannot address every type of infrastructure need. It only has potential value as an alternative to infrastructure projects that are being driven, at least in part, by load growth. Even then it will not always be applicable – either because the load reduction required is too great, or because it is needed too soon, because the economics of a particular application are not favorable, etc.

My experience with assessing the role that geographically-targeted DSM could play in cost-effectively deferring infrastructure investments – and I have studied every major example of such electric utility efforts over the past two decades, conducted trainings for system planners on how to integrate consideration of DSM into system planning, and am currently working on a pilot project with a Michigan utility – suggests that the key piece of new information most gas utilities would need to assess the potential role of efficiency in deferring infrastructure investments are hourly peak day load shapes (and/or an estimate of

[89] Neme, Chris and Rich Sedano, "U.S. Experience with Efficiency As a Transmission and Distribution System Resource", published by the Regulatory Assistance Project, February 2012 (see: www.raponline.org); and Neme, Chris and Jim Grevatt (Energy Futures Group), "Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments", published by Northeast Energy Efficiency Partnerships, January 9, 2013 (see: http://www.neep.org/initiatives/emv-forum/forum-products#Geotargeting).

X. Recommendations

Based on the analysis provided above, I recommend that the Board do the following:

1. Given the information now available on the scale of the rate reducing impacts of T&D avoided costs, commodity price suppression, reduced purchases of relatively expensive gas and emission reduction cost avoidance, the Board should eliminate the budget caps included in its earlier guidelines and thereby enable greater savings without undue rate impacts for DSM non-participants. This would accord with Government policy, including recent greenhouse gas policy announcements, and lead to an improved economic outcome.

2. Require future utility filings to include analysis of the combined effects of DSM spending and the rate reducing effects discussed above.

3. Require future DSM Plan filings to include analyses of the size of eligible markets for all proposed measures and programs. This will facilitate evaluation of the proposals and facilitate subsequent evaluation of performance as well. This could be required as added information in the Technical Resource Manual (TRM) for each measure.

4. Given the timing of this proceeding, approve the utilities' budgets and targets for 2015 unless information put before the Board by other parties suggests significant problems in the way they were developed. However Union should report its 2015 results using the Board's Framework cost-effectiveness policy – that is including the 15% non-energy benefits adder in the TRC test and a 4% discount rate.

5. Given the timing of this proceeding and the fact that that the utilities are planning to significantly ramp up their DSM efforts, approve the utilities' proposed 2016 budgets and targets except as follows:

   a. Require that Union continue to deliver its Large Volume program for the T2/R100 customers.

      i. The program budget for 2015 can be carried forward with a similar approach to setting the target as in previous years. This budget would be in addition to the budget Union has proposed for other customer classes for 2016.
      ii. The available shareholder incentive will need to be reallocated among the scorecards as a result of the addition of the budget for Large Volume T2/R100 program.
      iii. Consider allowing the self-direct funds to be spent over a multi-year period. This provides customers greater flexibility to plan large projects and should enable larger savings.
      iv. Preclude O&M projects with a payback of less than 1.5 or 2 years to reduce free ridership.
      v. Consider adopting the innovation that if customers can demonstrate