EB-2015-0029
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 applications for approval of 2015-2020 demand side management plans by Union Gas Limited and Enbridge Gas Distribution Inc.

ENVIRONMENTAL DEFENCE'S DOCUMENT BOOK FOR UNION GAS CROSS-EXAMINATIONS

August 19, 2015

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Lawyers for Environmental Defence

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Note: The above documents have been marked up by counsel. Most are excerpts of the relevant document.

[1] http://www.ieso.ca/Pages/Conservation/ConservatonFirstFramework/default.aspx
[2] http://www.hydroone.com/IndustrialLDCs/ConnectionProcess/Documents/Hydro%20One%20Tx%20Load %20Connection%20Customer%20Package.pdf
[3] https://www.enercare.ca/home/furnace/buynewfurnace#
custom5
[4] http://www.newyorker.com/magazine/2015/06/29/power-to-the-people

EB-2015-0029

Union Gas DSM Facts

Table 1: DSM Budgets, Savings and Net TRC: 2013 vs. 2020

	2013 (Actual)[i]	2020 (Proposed)[ii]	Change
Energy Conservation Budget	$32.8 million	$64.7 million	+ 97%
Net TRC	$326.3 million	$185.1 million	-43%
Cumulative Natural Gas Savings	2.8 billion cubic metres	1.3 billion cubic metres	- 54%

Table 2: Forecast Net TRC per $ of Union Gas Spending: 2016[iii]

Residential	$0.61
Commercial/Industrial	$7.11
Low Income	$0.01
Large Volume Industrial	0

Table 3: Forecast Net TRC of a Large Volume Direct Access Program per $ of Union Gas Spending: 2016[iv]

Large Volume Direct Access	$39.00

Table 4: Forecast Cumulative Natural Gas Savings per $ of Union Gas DSM Spending: 2016[v]

Residential	7.45 cubic metres
Commercial/Industrial	54.60 cubic metres
Low Income	4.49 cubic metres
Large Volume Industrial	0 cubic metres

Table 5: Forecast Cumulative Natural Gas Savings of a Large Volume Direct Access Program per $ of Union Gas Spending: 2016[vi]

Large Volume Direct Access	334.37 cubic metres

Table 6: Dawn Spot Price (Q1 average, 2015)[vii]

Dawn Spot Price $US/mmBTU	$3.66
Exchange Rate	0.77
Dawn Spot Price $CDN/1,000 cubic metres	$167.79

Table 7: Total Cost of Gas for T2 and Rate 100 Customers Assuming a Gas Commodity Cost of $167.79 per 1,000 Cubic Metres: 2016[viii]

Union Gas' Forecast Distribution Revenues	$66,092,000
Forecast Gas Commodity Costs	$919,862,909
Total Cost of Gas	$1,178,587,380

Table 8: Approximate Percentage Impact of a $4 Million Large Volume DSM Budget (Assuming Total Cost of Gas of $1,178,587,380 as in Table 7 Above)

Approximate Total Cost of Gas	$1,178,587,380
$4 Million DSM Budget	$4,000,000
Percentage Impact of DSM Budget on Gas Costs	0.3%

[i] Union Gas, *Final Demand Side Management 2013 Annual Report*, (November 4, 2014), pages 16, 17 & 18.
[ii] EB-2015-0029, Exhibit A, Tab 3, Pages 6 & 12; and Exhibit B.T3.Union.ED.12.
[iii] Union Exhibit A, Tab 3, Appendix A, Page 23, 49, & 96 [Net TRC]; Exhibit B.T3.Union.ED.10 [Budget].
[iv] EB-2015-0029, Exhibit B.T3.Union.ED.4, Page 1. We have divided the average net TRC for 2013 and 2014 by $4 million.
[v] EB-2015-0029, Exhibit A, Tab 3, Page 12; EB-2015-0029, Exhibit B.T3.Union.ED.3; and EB-2015-0029, Exhibit B.T3.Union.ED.10, Attachment 1.
[vi] EB-2015-0029, Exhibit B.T3.Union.ED.4, Page 1. We have divided the average cumulative natural gas savings for 2013 and 2014 by $4 million.
[vii] http://www.ontarioenergyreport.ca/pdfs/OntarioEnergyReportQ12015_OilGas_EN.pdf.
[viii] EB-2015-0029, Exhibit B.T3.Union.ED.6 and Exhibit B.T3.Union.ED.7.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Exhibit A, Tab 3, Appendix A, p. 64

This page describes the key features of Union's Large Volume (T2 and Rate 100) DSM program in 2013 and 2014.

Please provide Union's best estimates of the TRC Net Benefits and lifetime cubic metre savings that would be created if this program were to continue to operate in 2016 with a budget of: a) $4 million; b) $8 million; and c) $16 million.

Please assume that the key qualitative features of this Large Volume (T2 and Rate 100) DSM program in 2016 are the same as they were in 2013 and 2014, but with any adjustments as would be necessary to maximize the net TRC benefits.

Please provide a similar sensitivity analysis for 2017, 2018, 2019 and 2020.

Response:

Union's historical results for the Large Volume Direct Access program are outlined in Table 1. Please note that the 2014 figures are pre-audit and pre-verification.

Table 1

Year	Direct Access (Rate T2/Rate 100) Program Spend[1]	Cumulative Natural Gas Savings (m^3)	Net TRC
2013 Actual	$ 3,209,153	1,664,166,592	$ 221,142,333
2014 Pre-Audit	$ 3,255,408	1,010,819,454	$ 90,749,345

Union could potentially achieve similar annual results if the Direct Access Large Volume program were to be continued in 2016, with a total annual budget of approximately $4 million.

Availability of an $8 million budget could potentially result in approximately twice the results achieved with the 2013/2014 program, indicated above. However, Union expects that since the

[1] Union has allocated promotion, administration and evaluation costs by the percentage of customer incentive as allocated to Rate T2/ Rate 100

overall cost effectiveness of savings opportunities available to customers will decrease as the program size increases, the savings will diminish with budget allocated.

Union is unable to realistically estimate achievable savings considering a total annual budget of $16 million. Extrapolating lifetime savings results based on such a significant increase in budget is unrealistic.

Union notes that the customer rate impacts for its previous program with a budget of $4 million were of significant concern to Large Volume customers. Scenarios related to $8 and $16 million would greatly exacerbate these concerns.

1.3 Large Volume

Background

Following extensive customer consultation in 2012, Union designed and delivered a DSM Program specifically for its Large Volume (T2 and Rate 100) Customers in 2013 and 2014. The program includes the following key elements:

- Customer incentives for studies, custom projects, and metering.
- Union technical staff to assist customers with Energy Efficiency Plans and projects.
- Technical training courses
- A Direct Access Budget specific to each customer to provide clarity on the amount of incentives available
- Union performance incentives based on achievement level relative to natural gas savings targets

Through close collaboration between Union and Large Volume Customers, the program participation rate in 2013 was 82% of T2 and Rate 100 customers and increased to 95% in 2014. The audited program cost and lifetime savings in 2013 were $3.55 million and 1,664 million m^3 of natural gas respectively. These natural gas savings represent almost 60% of 2013 DSM program savings from all Union Rate Classes.

Under the new Framework, this program will conclude at the end of 2015

2015-2020 Demand Side Management Framework

The Framework offers the following conclusions to guide the design of a DSM Program for Large Volume Customers starting in 2016:

- No ratepayer-funded customer incentives
- Proposed fee for consulting service by Union technical experts
- Union performance incentives based on achievement level relative to natural gas savings targets
- Only portfolio-level staff costs can be ratepayer-funded

Customer Consultations

Union carried out consultations with 16 Large Volume Customers (44% of all Union’s Rate T2 and Rate 100 customers) in February and March 2015 to share the new Framework and understand what features and benefits the customers value in a utility energy efficiency program. The detailed responses are tabulated in Attachment A and the results are summarized here:

Ministry of Energy

Office of the Minister

4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
Fax: 416-327-6754

Ministère de l'Énergie

Bureau du ministre

4e étage, édifice Hearst
900, rue Bay
Toronto ON M7A 2E1
Tél. : 416 327-6758
Téléc. : 416 327-6754

Ontario

MAR 3 1 2014

MC-2014-875

Ms Rosemarie Leclair
Chair and Chief Executive Officer
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Dear Ms Leclair:

Enclosed is a copy of a Minister's Directive issued under sections 27.1 and 27.2 of the *Ontario Energy Board Act, 1998* approved by the Lieutenant Governor in Council on March 26, 2014.

The Directive requires the Board to take steps to promote electricity conservation and demand management and natural gas demand side management consistent with the Government of Ontario policy of putting conservation first as adopted in its 2013 Long-Term Energy Plan, *Achieving Balance*.

I would appreciate the Board proceeding to take appropriate steps to implement the attached Directive.

Sincerely,

Bob Chiarelli
Minister

Enclosure

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.

Home > Conservation > Conservation First Framework

Conservation First Framework

Ontarians have embraced conservation, and its role in meeting electricity demand is only growing. Conservation First is the guiding principle that now places conservation at the forefront of Ontario's energy planning and procurement processes, ensuring it is the first option to be considered in planning for electricity needs.

The new Conservation First Framework maps out Ontario's energy conservation goals over the next six years, emphasizing a coordinated effort within all stages of energy planning, as well as more effective teamwork among sector partners, particularly in support of local distribution companies (LDCs).

Also in this section

Conservation and Demand Management Plans

See also

saveonenergy.ca

Industrial Accelerator Program

The Framework

The goal of the framework is a total reduction of 8.7 TWh of electricity consumption in Ontario by December, 2020 — 1.7 TWh to be achieved through conservation projects with transmission-connected customers, and 7 TWh from conservation programs delivered by LDCs to residential and business customers across the province.

Greater Autonomy for Distributors

The framework gives a much larger role to the province's distributors, each being assigned a share of the 7 TWh target that they can pursue individually or in partnership with other LDCs.

The IESO is providing tools, support and guidance to LDCs to help them meet their targets through the development of a six-year Conservation and Demand Management (CDM) Plan. The plan allows LDCs to design their own program offerings, giving them greater flexibility to align conservation programs to local needs, and give customers more choice. It will also ensure long-term, stable funding to give LDCs the certainty they need to implement and deliver their programs. In addition, new administrative requirements now mean the IESO has sole approval over plans and program offerings, ensuring oversight while still streamlining processes. More on CDM plans »

Collaboration and Partnerships

Collaboration, to maximize efficiencies and reduce costs, is a key focus in the new Framework. The IESO is working closely with LDCs, who are in turn encouraged to partner with other utilities to meet energy reduction targets. Examples of how teamwork is encouraged include:

- A simplified approval process for combined CDM plans of two or more LDCs;
- The provision of a specialized template and materials to help utilities adopt a regional approach to resourcing;
- The encouragement of partnerships, where appropriate, with natural gas distributors, for cooperating in areas such as marketing and customer engagement where they share customers or program goals with LDCs;
- Additional financial support through the IESO, above and beyond CDM Plan budgets, for groups of collaborating LDCs that partner within their respective regions or with utilities that share similar opportunities and challenges.

Regional and Community Planning Integration

With an eye to ensuring coordination within the sector, LDCs are required to describe how their conservation programs consider needs and investments identified in other stages of energy planning, including Integrated Regional Resource Planning, distribution system plans, and community energy plans.

By sharing CDM plans and associated activities, LDCs give other planners information on program commitments and projected savings, and in turn can better identify areas for focusing resources and partnering with other utilities. LDCs can, for example, target programs and marketing to customers in areas with greater energy requirements.

Contributing to and benefiting from these initiatives could ultimately help achieve local reliability at a lower cost to ratepayers.

Although CDM plans focus on 2015-2020 period, the work they do may lay the groundwork for achieving savings that address the longer-term needs identified through regional planning.

Read more about regional planning in Ontario.

Transmission-Connected Customer Targets

The 1.7 TWh reduction target will be delivered through the Industrial Accelerator Program, which offers financial incentives to industrial, commercial and institutional customers directly connected to the electricity grid. Incentives encourage the implementation of major energy conservation projects, such as process changes and equipment retrofits.

In response to stakeholder feedback, the IESO is currently refining the program design to improve the customer experience and streamline administration. More on the Enhancements to the IAP »

Innovative Program Design Elements

- The new Framework promotes innovation and the adoption of new technologies through the LDC Program Innovation Stream. The Stream provides additional funding for LDC-led program design and market testing of small-scale pilot programs, which refine program delivery at less risk to the ratepayer.
- The IESO will begin to formally include benefits not directly related to energy savings when weighing the total costs and benefits of proposed conservation programs. These include environmental, economic and social benefits, like increased comfort, reductions in carbon emissions, and better air or water quality, and highlight the advantages of conservation to society as a whole.
- Energy managers are professionals trained to identify areas for energy efficiency and improvement, often with specific expertise within a sector or an area like lighting. The IESO is working with LDCs to develop a complimentary layer of support to ensure the availability of this service throughout the province, particularly for smaller LDCs.

Contact Us »
General Enquiries
Toll Free: 1.888.448.7777
Telephone: 905.403.6900
Email: customer.relations@ieso.ca

LDC 2015-2020 CDM Plans

1. Could you please provide the IESO's total budget for the LDCs' 2015-2020 CDM programs.
The sum of all LDC budgets is $1,835,264,931. The central services budget (e.g. EM&V, LDC innovation pilots, province-wide marketing, market research, etc.) is $400 million.
These values are available online at

http://www.powerauthority.on.ca/sites/default/files/conservation/LDC%20CDM%20Targets%20and%20Budgets_10312014.pdf

2. Could you please provide a break-out of the 2020 7 TWh savings target by LDC.
See above.

3. Could you please provide your best estimate of the cumulative, life-time TWh savings that will be created by the LDCs' 2015-2020 CDM programs.
Until all CDM Plans are approved, the IESO is unable to provide an estimate of the cumulative, life-time savings from the programs.

4. Could you please provide the time horizon(s) that the LDCs are required to use when calculating the TRC benefits of their CDM programs.
The TRC benefits are calculated for 2015-2020, and benefits include the lifetime savings of the measures.

5. Could you please provide the annual avoided cost estimates that the IESO provides to the LDCs to calculate the TRC benefits of their CDM programs.
This is included in Appendix A, p. 58, of the CDM Cost Effectiveness Guide available online at
http://www.powerauthority.on.ca/sites/default/files/conservation/CDM%20EE%20Cost%20Effectiveness%20Test%20Guide%20Final%20v1_10312014.pdf

Could you please state when these avoided cost estimates were prepared.
2014.

Could you please provide a description of the IESO's avoided cost methodology and its key input assumptions.

The following is an overview of the IESO's avoided costs used in the evaluation of electricity conservation programs:

- Electricity conservation program avoided costs are used to support the design and prioritization of conservation programs
  - March 2014 CDM Framework Directive requires a positive benefit-cost result for each program
  - Update included in the cost-effectiveness tool released to LDCs on July 31, 2014
- The avoided costs are an output of the Long-Term Energy Plan (LTEP) and values reflect the electricity resource mix described in LTEP 2013
  - Does not change CDM program targets or budgets, to be used as a tool by LDCs for program cost-effectiveness screening
  - Targets are based on achievable potential (see IESO 2014 Achievable Potential Study posted on IESO website) and are expected to be achieved cost-effectively
  - Compared to the avoided costs last published, in 2010, updated Avoided Costs are lower in the near term (to 2020) driven by current supply/demand outlook (per LTEP), approach 2010 values in the long term (post 2020)

Cost assumptions are set out in the Cost Effectiveness guide, and include:

- Inflation rate 2%
- Discount rate 4%
- Base year 2014
- Average distribution system losses 4.20%
- Average transmission system losses 2.50%
- Non-energy benefits rate 15%
- Avoided energy and capacity values are set out at page 58 of the CDM Energy Efficiency Cost Effective Guide Final v.1

http://www.powerauthority.on.ca/sites/default/files/conservation/CDM%20EE%20Cost%20Effectiveness%20Test%20Guide%20Final%20v1_10312014.pdf

6. Could you please provide a copy of the IESO's generic contract with the LDCs with respect to their 2015-2020 CDM Programs' budgets and targets. In particular, I am interested in understanding the incentives that the IESO is providing to the LDCs' shareholders to meet and exceed their CDM targets and to underspend their CDM budgets.
The Energy Conservation Agreement is available online at
http://www.powerauthority.on.ca/sites/default/files/conservation/Energy-Conservation-Agreement.pdf

2015-2020 CDM Programs for Transmission-Connected Customers
1. Could you please state the IESO's budget to achieve its 1.7 TWh CDM savings target for transmission-connected customers by 2020.
$500 million

2. Please provide your best estimate of the cumulative, life-time TWh savings that will be created by your transmission-connected customers CDM programs, which will provide annual savings of 1.7 TWh in 2020.
The cumulative life-time TWh savings depend on the timing of when savings occur. There is a steady ramp up period of adoption of energy efficiency measures, to reach to goal of 1.7 TWh in 2020.
Using a ball-park assumption of a 20-year lifespan for persistence in efficiency measures (the precise values are based on the individual measures assumption list: http://www.powerauthority.on.ca/opa-conservation/conservation-information-hub/evaluation-measurement-verification/measures-assumptions-lists) one could assume that the measures that go in place for 2020 have a 20 year persistent savings of 1.7 TWh per year, and for planning purposes assume that the measures begin to ramp down in 2035.

3. Please provide your best estimate of the TRC benefits and costs of your CDM programs that will save 1.7 TWh in 2020.
The Board has approved a TRC of 1.4 and a LUEC of $40/MWh.

FW: CDM questions - part 1

1 message

Jack Gibbons <jack@cleanairalliance.org> Thu, Jul 23, 2015 at 3:08 PM
To: Kent Elson <kent.elson@klippensteins.ca>

Hi Kent,

This email and attachment are for our Union Gas Cross-Examination Document Book.

All the best,

Jack

From: Young, Terry [mailto:terry.young@ieso.ca]
Sent: July-13-15 4:54 PM
To: 'Jack Gibbons'
Subject: RE: CDM questions - part 1

Jack, I am doing this in two batches ... here is the first one. The second will follow tomorrow. Appreciate your patience on this.

Terry

-

-----Original Message-----
From: Jack Gibbons [mailto:jack@cleanairalliance.org]
Sent: July 10, 2015 4:16 PM
To: Young, Terry
Subject: Re: CDM questions

Thanks Terry. Monday would be great - I don't want you to have to work this weekend!

All the best,

Jack

Sent from my iPad

> On Jul 10, 2015, at 4:06 PM, Young, Terry <terry.young@ieso.ca> wrote:

>

> Jack:

>

> I have most of the stuff together. I have a few links I need to check but will do that over the weekend and send you something Sunday or Monday.

>

> Have a good weekend.

>

> Terry

>

> -----Original Message-----

> From: Young, Terry

> Sent: July 07, 2015 10:12 AM

> To: Jack Gibbons

> Subject: Re: CDM questions

>

> Jack: Thanks for the reminder. Yes I should have something for you this week. Terry

>

> Sent from my BlackBerry 10 smartphone on the Bell network.

> Original Message

> From: Jack Gibbons

> Sent: Tuesday, July 7, 2015 9:31 AM

> To: Young, Terry

> Cc: Veeneman, Kimberly

> Subject: RE: CDM questions

>

>

> Hi Terry,

>

> I hope you are enjoying the warm weather.

>

> Just checking in to see if you will be able to give me a CDM progress report soon?

>

> All the best,

>

> Jack

>

> Jack Gibbons

> Chair, Ontario Clean Air Alliance

> 160 John St., #300

> Toronto M5V 2E5

>

> Tel: 416-260-2080 x 2

> Fax: 416-598-9520

> Email: jack@cleanairalliance.org

> www.cleanairalliance.org

>

>

>

> -----Original Message-----

> From: Young, Terry [mailto:terry.young@ieso.ca]

> Sent: June-15-15 5:08 PM

> To: Jack Gibbons

> Cc: Veeneman, Kimberly

> Subject: RE: CDM questions

>

> Jack: There is a lot here but we will get started on answering the questions. I will give you a progress report in a week. Terry

>

> -----Original Message-----

> From: Jack Gibbons [mailto:jack@cleanairalliance.org]

> Sent: June 15, 2015 1:37 PM

> To: Young, Terry

> Subject: CDM questions

>

> Hi Terry,

>

> I hope you are well.

>

> I have a number of CDM and integrated resource planning questions for the IESO which I am hoping that your staff can answer.

>

> My questions are attached.

>

> Thanks for your help.

>

> Jack

>

> Jack Gibbons

> Chair, Ontario Clean Air Alliance

> 160 John St., #300

> Toronto M5V 2E5

>

> Tel: 416-260-2080 x 2

> Fax: 416-598-9520

> Email: jack@cleanairalliance.org

> www.cleanairalliance.org

>

>

>

Response Jack Gibbons questionsJuly 2015 part 1.docx
26K

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Exhibit A, Tab 3, Appendix A, p. 64

Please estimate the revenue requirement impacts in 2016 and 2017 of 2016 Large Volume DSM budgets of: a) $4 million; b) $8 million; and c) $16 billion assuming that they are rate-based and amortized over the expected lives of their lifetime cubic metre savings.

Response:

Please see Attachment 1 for the hypothetical requested estimate for 2016 and 2017 revenue requirement impacts. Please also see the response at Exhibit B.T13.Union.ED.19.

Filed: 2015-06-23
EB-2015-0029
Exhibit B.T3.Union.ED.5
Attachment 1

Hypothetical Revenue Requirement Impacts

Assumptions (1)	
in-service month	November
depreciation (in years)	14.00
equity return	8.93%
deemed equity structure	36.00%
debt return	4.00%
tax rate	26.50%

Line No.	Particulars ($000's)	$4 million 2016 (a)	$4 million 2017 (b)	$8 million 2016 (a)	$8 million 2017 (b)	$16 million 2016 (a)	$16 million 2017 (b)
	Rate Base Investment						
1	Capital Expenditures	4,000	0	8,000	0	16,000	0
2	Average Investment	429	3,714	857	7,429	1,714	14,857
	Revenue Requirement Calculation:						
	Operating Expenses:						
3	Operating and Maintenance Expenses	0	0	0	0	0	0
4	Depreciation Expense (2)	143	286	286	571	571	1,143
5	Property Taxes	0	0	0	0	0	0
6	Total Operating Expenses	143	286	286	571	571	1,143
7	Required Return (3)	25	214	49	429	99	858
8	Total Operating Expense and Return	168	500	335	1,000	670	2,001
	Income Taxes:						
9	Income Taxes - Equity Return (4)	5	43	10	86	20	172
10	Income Taxes - Utility Timing Differences (5)	(1,391)	103	(2,781)	206	(5,563)	412
11	Total Income Taxes	(1,387)	146	(2,772)	292	(5,544)	584
12	Total Revenue Requirement	(1,219)	646	(2,438)	1,293	(4,873)	2,585

Notes:

(1) Assumptions are best estimates at the time of response preparation and are subject to change
(2) Depreciation expensed assumed based on a useful life of 14 years.
(3) The required return assumes a capital structure of 64% long-term debt at 4% and 36% common equity at the 2013 Board-approved return of 8.93%.
(4) Taxes related to the equity component of the return at a tax rate of 26.5%.
(5) Taxes related to utility timing differences are negative as the expense deduction in arriving at taxable income exceeds the provision of book depreciation in the year.

EB-2012-0337

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Union Gas Limited pursuant to Section 36(1) of the *Ontario Energy Board Act, 1998*, for an Order or Orders approving the 2012 to 2014 Demand Side Management Plan.

APPLICATION

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

2. Union conducts an integrated natural gas utility business that combines the operations of selling, distributing, transmitting and storage of gas and a non-utility storage business.

3. On June 30, 2011, the Ontario Energy Board (the "OEB" or the "Board") issued the Demand Side Management ("DSM") Guidelines for Natural Gas Utilities (the "Guidelines"). The Board noted the natural gas utilities were expected to develop their DSM plans in accordance with the Guidelines, and to submit those plans to the Board for approval.

4. Union applied to the Board on September 23, 2011, pursuant to Section 36 of the *Ontario Energy Board Act* for an Order or Orders effective January 1, 2012 approving Union's DSM Plan for the years 2012, 2013 and 2014. The docket number of this proceeding was EB-2011-0327.

5. The EB-2011-0327 Settlement Agreement ("Agreement") was filed on January 31, 2012. The Agreement on page 26 states, "The Participating Parties have agreed that the DSM

> *"The development and design of a rate or rate class is a process that is governed by principles which have been developed by scholars and practitioners. Principles are necessary because of the high degree of interdependence of gas distribution system participants. Of all the principles governing the establishment of rates and rate classes, the most fundamental is that requiring that rate classes should be responsible for a reasonable proportion of the costs they cause the system to incur".*
>
> *The revenue requirement established by the Board in rates cases such as the present case represents the system's overall financial burden. In order for rates to be just and reasonable, which is the statutory requirement, each rate class should bear a proportion of that burden roughly coincident with the costs incurred by the system operator, in this case Union Gas, in providing the necessary infrastructure and services to arrange for, store and transport the commodity to that rate class' members." (emphasis added)*

In effect large volume customers who want to opt-out of DSM programming are seeking special rate treatment at the expense of other customers in the class. Union currently offers DSM programming to all rate classes to which it provides regulated distribution, transmission and storage services. To offer an opt-out option to large volume customers would also create an inappropriate inconsistency with other rate classes.

7.2 The Board's Guidelines and Union's Proposed Plan Address Many Customer Concerns

Union understands that the customers seeking the option to opt-out are doing so for three primary reasons. They are:

1. The customer is of the view that there are no further DSM opportunities for them to take advantage of;
2. The customer is implementing DSM initiatives on their own and does not require utility DSM programming; and
3. The disposition of DSM-related deferral accounts have resulted in significant unexpected out-of-period adjustments.

With respect to Items 1 and 2, it is Union view, notwithstanding the principles of class ratemaking described above, that utility DSM programming continues to provide value for all customers. With the current low price of gas, DSM programming for all customers ensures that energy conservation remains a priority. Despite commodity price fluctuations, a sustained focus on energy-efficiency is important for the long-term environmental sustainability and economic competitiveness of Ontario. Payment of DSM funding ensures there is no internal competition for this budget for other uses within a customer's organization. It is a driver for large volume organizations to leverage ratepayer-funded technical support to seek out conservation opportunities within their facility. Union's proposed Direct Access program design incorporates the key elements of a self-direct program but has been tailored for Union's customers based on Union's knowledge of the market requirements and customer feedback. The proposed Plan, and in particular Union's proposals related to Direct Access, ensures that energy conservation continues to be a priority for large volume natural gas consumers in Ontario. Union further notes that in most jurisdictions where opt-out is a feature of a DSM plan, customers are required to demonstrate to the regulator that they are in fact undertaking DSM initiatives.

With respect to Item 3, the Guidelines and proposed Plan directly address the concerns related to the significant, unexpected, out-of-period adjustments possible under the DSM Plan ("Old Plan") in place prior to 2012.

Under the Old Plan, Union had no limit to the amount that could be spent in a rate class and the ability to increase DSM program spending by 15% of the total DSM budget. The additional 15% of available DSM program funds were not capped for any rate class. To the extent that DSM spending differed from the rate class allocation or Union accessed the additional funds, the variance was allocated to rate classes in the DSMVA in proportion to actual DSM spending by rate class. Since the amounts were not capped at the rate class level, this resulted in significant charges attributable to individual rate classes.

Although the Guidelines did not address these issues, the Agreement limited the following items: the overall Large Industrial program budget, the amount ($0.5 million) which may be transferred between large volume rate classes within this program budget, and the amount of the 15%

available overspend that could be applied to the Large Industrial program. Union is proposing to extend these limitations in the Plan proposed for Rate T1, Rate T2 and Rate 100. Further, Union has removed the ability to overspend the Plan budget by 15% in Rate T2 and Rate 100.

The Guidelines and the proposed Plan also address the amount and allocation of the DSM incentive. Under the Old Plan, the maximum 2011 Shared Savings Mechanism ("SSM") DSM incentive was $9.2 million and was allocated to rate classes in proportion to TRC savings. The allocation of the SSM in proportion to TRC resulted in significant charges being attributed to large volume rate classes.

Per the Guidelines, the DSM incentive attributable to any rate class is allocated in proportion the actual DSM spending for that rate class. As indicated above, Union is proposing to extend the limitations on DSM spending for the large volume rate classes in 2013 and 2014 consistent with the Agreement. Accordingly the maximum DSM incentive attributable to Rate T1, Rate T2 and Rate 100 will also be limited and known in advance.

8. PENDING BOARD DECISION ON PROPOSED T2 RATE STRUCTURE

In the event the proposed T2 rate structure is not approved by the Board, the budget transfer and allocation amounts between Rate T1 and Rate T2 would no longer apply. The 2013 and 2014 Large Volume DSM budget would be allocated 70% to Rate T1 and 30% to Rate 100. In the event Union qualifies to access the 15% allowable overspend, Union will access up to a maximum of 15% of the program and portfolio budget allocated to Rate T1, Rate T2 and Rate 100. This maximum overspend may be allocated to programming for Rate T1, Rate T2, Rate 100, or any combination, at Union's discretion. These budget conditions are consistent with 2012.

The Direct Access budget mechanism for Rate 100 customers would remain as outlined above. This Direct Access budget mechanism would also be applied to all Rate T1 customers with a minimum firm daily contracted demand of 140,870 m^3 based on the 2013 Test Year Forecast for Rate T1. This threshold is consistent with the Rate T2 criteria proposed in Union's 2013 Cost of Service Application (EB-2011-0210).

EB-2012-0337

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Union Gas Limited pursuant to Section 36(1) of the *Ontario Energy Board Act*, *1998*, for an Order or Orders approving the 2013 to 2014 Demand Side Management Plan.

REPLY ARGUMENT OF UNION GAS LIMITED

Overview

1. This is Union's Reply Argument, which should be read in conjunction with Union's Argument-in-Chief. Union remains of the view that its application, which is supported in most respects by Board Staff and all intervenors other than APPrO, should be approved as filed. Union's reply to the arguments raised by intervenors and Board Staff are set out below on an issue-by-issue basis. All references are to Union's Reply Compendium.

Opt-out

2. Union relies on its Argument-in-Chief.[1] APPrO's argument failed to meaningfully address the fatal flaw in its proposal pointed out by Union[2] and by Union's witness Mr. Tetreault: an opt-out option for APPrO members would be contrary to the fundamental class ratemaking principle that "all customers in the class pay the same rates".[3] A departure from this principle would invite a flood of similar requests for special exemptions, both within large-volume rate classes and in other rate classes. As the argument of SEC suggests, the claim that a subset of a rate class deserves a special exemption inevitably leads other subsets of that rate class to insist that they too deserve special exemptions.[4] If successful, this argument will encourage

[1] Tab 1; Transcript Vol. 2, pp. 129-135

[2] Tab 1; Transcript Vol. 2, pp. 131-133

[3] Tab 2; Transcript Vol. 1, pp. 126-127

[4] Tab 3; School Energy Coalition ("SEC") Final Argument

do not pay for DSM is because that class does not, and has never been included in DSM programming.[12]

6. IGUA notionally took no position on opt-out, albeit with the qualification that opt-out, if pursued at all, should "be pursued on a rate-class basis and not on a customer basis".[13] In Union's submission, this is really a position against opt-out. APPrO's request for an opt-out is opposed in substance by all other parties and should be rejected.

Jurisdictional Review

7. APPrO argues that Navigant's jurisdictional review "demonstrates that non-mandatory participation in DSM in the rest of Canada and in the U.S. ultimately is more the norm for large gas-fired generators than otherwise".[14] Union submits that what APPrO terms "non-mandatory participation in DSM" is, at best, a conflation of a variety of initiatives in varied regulatory contexts across North America and, at worst, a euphemism for no DSM at all.

8. Navigant's jurisdictional review was not sufficiently detailed and contextual to ground APPrO's argument that "non-mandatory participation in DSM" is the norm for large gas-fired generators. The jurisdictional review section of the Navigant report is five pages long. The a-contextual nature of the inquiry Navigant was asked to perform is demonstrated by the fact that Navigant stated in its report that one of the considerations informing the Minnesota Public Utilities Commission's decision to exclude generators from paying DSM CRM was that it would result in a double payment, but acknowledged in an interrogatory response that it had "no additional information on other reasons or considerations" that informed the decision.[15] Such an inquiry does not provide an adequate evidentiary basis for APPrO's assertion that "non-mandatory participation in DSM" is the norm for large gas-fired generators in North America. APPrO's argument also ignores the fact that only one of the top twenty jurisdictions in North

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[12] Tab 11; Transcript Vol. 2, pp. 104-105

[13] Tab 12; Transcript Vol. 3, pp. 31-32

[14] Tab 13; Transcript Vol. 3, pp. 52-53

[15] Tab 14; Navigant Report, pp. 5-6; APPrO Response to GEC Interrogatory 12(c)

America offers an opt-out program. That program requires the opting-out customer to spend $3 million on energy-efficiency investments over the three-year period of the pilot program.[16]

9. Finally, Union submits that APPrO's argument about "non-mandatory participation in DSM" clouds the distinction between Union providing DSM to large-volume customers, which is not mandatory under the DSM Guidelines,[17] and large-volume customers' funding of costs that have been allocated to their rate class, which is mandatory under the fundamental principles of class ratemaking.

APPrO's Flawed and Misleading "Eight Cents on the Dollar" Argument

10. APPrO argues that Union's DSM program has had a "hugely disproportionate negative impact" on power generators because over the 2009-2011 period they paid $9.448 million for DSM programming and received approximately $700,000 in customer incentive. APPrO submits that the $9.448 million number should be reduced to $9.1 million to exclude LRAM costs and argues that the $9.1 million-$700,000 ratio represents "eight cents on the dollar", which is a "stark number".[18]

11. This argument is flawed and misleading, primarily because it ignores three things. First, it ignores the Total Resource Costs (TRC) benefits power generators received as a result of participating in Union's DSM programs from 2009-2011. TRC benefits, which are net of free ridership, benefit power generators by helping them achieve long-term savings. On the basis of evidence filed in this proceeding the TRC benefits that power generators secured in 2009-2011 will be in the range of $47 million. This projection is based on the following calculation of TRC benefits.

[16] Tab 15; Exhibit A, Tab 1, Appendix A, p. 3

[17] Tab 16; Transcript Volume 3, p. 53

[18] Tab 17; Transcript Vol. 3, p. 54

TRC benefits ($47,583,563) = cost effectiveness ratio of 8.1[19] x [(1 - free ridership of 0.56)[20] x (incremental project costs funded by power producers of $12.540 million)[21] + (the three-year average percentage of DSM paid in rates by powers producers of 30.75%)[22] x (large-volume promotion costs of $100,000 + administration costs of $906,511 + EM & V costs of $40,000)][23]

12. Second, this argument fails to distinguish between DSM in the 2009-2011 period, under the old framework (EB-2006-0021) and DSM Plans, and the program that Union is applying for in this application, which Union has brought in the context of the current DSM Guidelines (EB-2008-0346) and the 2012 Settlement Agreement. The Guidelines and proposed Plan directly address APPrO's concerns around significant costs for its members and unexpected out-of-period adjustments that were possible during, and materialized in, the 2009-2011 period. Under the old Framework the SSM was allocated to rate classes in proportion to TRC savings resulting in significant charges attributed to large-volume rate classes. There was no limit to the budget amount that could be spent in a rate class and no limit to the amount of the total 15% overspend that could be allocated to large-volume customers. The Guidelines addressed the first issue by allocating the DSM Incentive to rate classes in proportion of the amount actually spent in each rate class. The 2012 Settlement Agreement addressed the second issue by limiting the Large Volume Program budget, the amount which may be transferred between rate classes within this budget, and the amount of the 15% overspend that could be applied to this program. Union's 2013-2014 proposal extends these limitations. Further, Union has removed the ability to overspend the Plan budget by 15% in Rate T2 and Rate 100 and provided these customers with direct access to the customer incentive budget they pay in rates. The result is a stable annual DSM cost to these

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[19] Tab 18; Exhibit A, Tab 1, p. 30

[20] Tab 19; Exhibit A, Tab 1, Appendix E, p. 5

[21] Tab 20; Exhibit J1.4, p. 117

[22] Tab 21; Exhibit B6.2, Attachment 1; Exhibit J1.5, Attachment 1, Attachment 2;

[23] Tab 22; Exhibit A, Tab 1, p. 30

customers, and predictability in both the amount they pay for DSM and the customer incentive available for each customer.

13. Third, APPrO's argument ignores the SSM in the $9.448 million amount used in this calculation. This amount is $4.272 million[24] over the three year period. In Union's proposal, the maximum DSM Incentive is limited for all Rate T1, Rate T2 and Rate 100 customers to approximately $1.8 million per year. Using the 2009-2011 percentage of large volume DSM costs paid by power producers of 30.75%[25] as an estimate of their level of funding in the 2013-2014 period, a maximum of approximately $0.6[26] million of this could be allocated to APPrO members per year. It is significantly reduced from the SSM funded by these customers in the 2009-2011 period.

Cross-subsidization

14. APPrO argues that Union's DSM program has resulted in cross-subsidization within large-volume rate classes.[27] Union notes that the evidence relied on by APPrO -- Undertaking J1.5, Interrogatory B6.8 and Tab 5 of APPrO's Final Argument Compendium -- is evidence in respect of all Rate T2 and Rate 100 customers. This evidence does not differentiate between power producers and other customers. This evidence is not an adequate basis for arguing that power producers are cross-subsidizing other customers in their rate classes.

15. Regardless of the merits of this argument, it disregards the fact that Union's application features a direct access mechanism for Rate T2 and Rate 100 customers,[28] which allows customers with concerns about cross-subsidization to simply access their customer incentives before others in their rate class have an opportunity to do so. Similarly, APPrO's proposal to cap customers' access to program funds to 150% of their contributions[29] ignores the fact that Union's

[24] Tab 23; Exhibit J1.5, Attachment 1, Attachment 2.

[25] Use footnote to calculation in 11 above.

[26] Calculated as $1.8 million * 30.75%

[27] Tab 24; Transcript Vol. 3, pp. 55-59

[28] Tab 25; Exhibit A, Tab 1, p. 7

[29] Tab 26; Transcript Vol. 3, p. 90

INTERROGATORY #2

Ref: Navigant Consulting, *DSM Funding Options for Large Natural Gas Customers*, page 18

If the Ontario Energy Board ("OEB") were to permit the "opting out" option, do you believe that the expected magnitude of natural gas savings (cubic metres) would rise, fall or stay the same for the customers that opted out? Please fully justify your response.

RESPONSE

Navigant does not have sufficient information from the survey to respond to this question.

20,

VERESEN

Veresen Inc.
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222 – 3rrd Avenue S.W.
Calgary, Alberta T2P 0B4

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October 11, 2011

Via Electronic Mail

John Pickernell
Board Secretary
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Atten: Board Secretary

Re: Demand Side Management Guidelines for Natural Gas Utilities
Issuance of DSM Guidelines

Further to the Ontario Energy Board's (OEB) letter dated June 30, 2011, regarding the Demand Side Management (DSM) Guidelines for natural gas utilities, Veresen Inc., (Veresen) wishes to express its views. Veresen is a publically traded energy infrastructure company that holds energy assets in Ontario consisting of natural gas fired electricity generation facilities including district heating, cogeneration and peaking generation, ranging in size from 15 MW to 400 MW.

Two of Veresen's facilities, the East Windsor Cogeneration Centre (EWCC) and our London District Energy (LDE) facility currently hold Union's T1 service contracts and thus are subject to the T1 rate class methodology. Both of these facilities have participated in the DSM programs offered through Union Gas with very good success. Veresen's position regarding this program is that it has played an important role in achieving increased energy effeciency at these facilities. In our view, eliminating these programs is not in the best interest of T1 shippers and importantly, may result in a reduction in DSM initiatives by generators such as ourselves. EWCC and LDE are not large industrials, and therefore the view's expressed by others such as IGUA or CME regarding the DSM program, are not representative of our position.

Veresen strongly encourages the Board to continue the DSM program as currently structured to further facilitate achivements in DSM in Ontario.

Yours truly,

J Ciccaglione

Julia Ciccaglione
Vice President, Regulatory & Government Affairs
Veresen Inc.

Cc: Paul Eastman, VP Operations - East, Veresen Inc.

TRANSMISSION LOAD CONNECTIONS

HYDRO ONE NETWORKS INC.
SEPTEMBER 2014

Important Information for Transmission Load Customers

This package was published for Hydro One's Tx Load Connection Customers as a supplement to the "Transmission Connection Procedures" document, which outlines the complete process and requirements and is available at http://www.hydroone.com/IndustrialLDCs/ConnectionProcess/Pages/GettingStarted.aspx. We highly encourage customers to review the Transmission Connection Procedures and ensure they are aware of all required approvals, processes, organizations and costs prior to undertaking the application process. Failure to do so may cause delays in the process. Also, this package is in no way intended to be interpreted as the views of any other organization. For more information on the process please visit http://www.hydroone.com/Generators/Pages/Transmission-connected.aspx. Any questions regarding the process can be directed to your Hydro One Account Executive or LargeAccounts@HydroOne.com.

TRANSMISSION LOAD CUSTOMERS

Hydro One is proud to supply electricity to over 90 transmission-connected Large Industrial Customers, close to 100 transmission-connected Generators and over 70 Local Distribution Companies (LDCs) across Ontario. All of these Customers have significant power requirements.

Hydro One's Transmission Load Customers must follow a comprehensive process in order to become connected to the transmission system. The information in the **Transmission Load Connection Customer Package** helps to clarify the process by providing important information that Customers should know prior to connecting their facility. Customer must also review the "Transmission Connections Procedures" document for detailed process information.

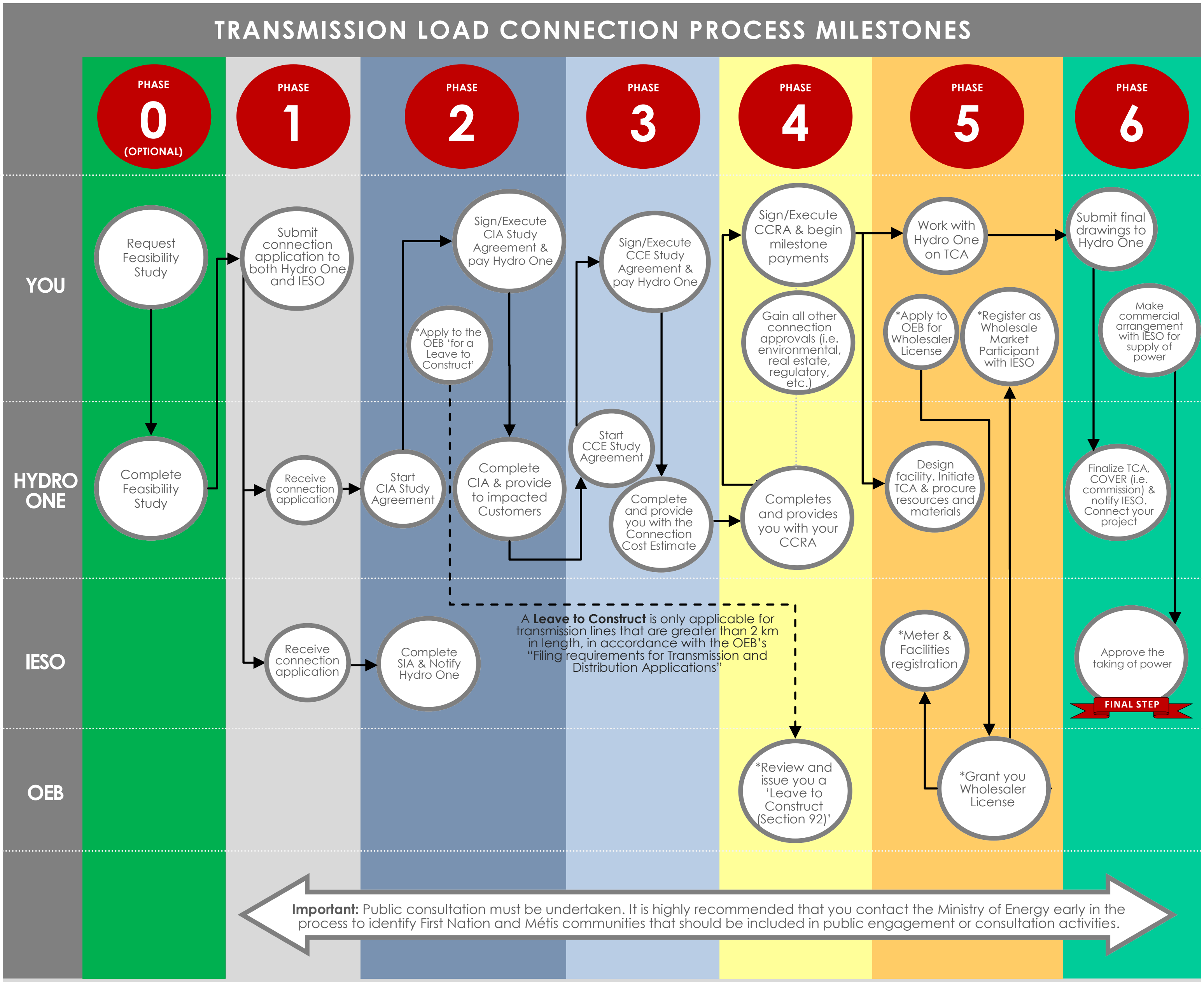
The Transmission Load Connection Customer Package also assists Customers who are requesting a new or modified connection to Hydro One's transmission system. The process is consistent with the transmission connection procedures that have been filed with the Ontario Energy Board (OEB).

Transmission Load Connections

PROCESS, MILESTONES & KEY PLAYERS

Important: The complexity of your project and the associated appraisals required throughout the process could have a significant impact on your project's timelines. They can include but are not limited to Ontario Energy Board (OEB) approvals (e.g. Leave to Construct), environmental approvals, municipal approvals and permits, including land easements and land acquisitions.

TRANSMISSION LOAD CONNECTION PROCESS MILESTONES



CIA = CUSTOMER IMPACT ASSESSMENT, **SIA** = SYSTEM IMPACT ASSESSMENT, **IESO** = INDEPENDENT ELECTRICTY SYSTEM OPERATOR, **OEB** = ONTARIO ENERGY BOARD, **CCE** = CONNECTION COST ESTIMATE, **CCRA** = CONNECTION COST RECOVERY AGREEMENT, **TCA** = TRANSMISSION CONNECTION AGREEMENT, **COVER** = CONFIRMATION OF VERIFCATION EVIDENCE REPORT, **SLD** = SINGLE LINE DIAGRAM

ROLES OF KEY PLAYERS IN ONTARIO'S ELECTRICITY INDUSTRY

HYDRO ONE

Utility and licensed Transmitter. Responsible to operate and maintain the Transmission System, including new connections once approved. Physically connects your facility and ensures saftey.

www.HydroOne.com

INDEPENDENT ELECTRICITY SYSTEM OPERATOR (IESO)

Manages supply and demand of electricity. Directs flow of electricity across Ontario

www.ieso.ca

ONTARIO POWER AUTHORITY (OPA)

Plans and procures electricity supply through various energy programs for the Ontario Government.

www.powerauthority.on.ca

CONSUMER (YOU)

Builds and connects facilities to the electrical grid.

Ensure to review websites

ONTARIO ENERGY BOARD

Governs the legislation and regulations (Transmission System Code and Distribution System Code)

www.ontarioenergyboard.ca

ELECTRICITY SAFETY AUTHORITY

Enhances public electrical safety in Ontario

www.esasafe.ca

Important: This document is a supplement to the "Hydro One Transmission Connection Procedures" document. Customers should refer to the Procedures document, as well as the Independent Electricity System Operator's and Ontario Energy Board's Transmission Load Connection documents and processes.

hydro one

PAYMENTS, TIMELINES & REQUIREMENTS

	DEVELOPMENT					CONSTRUCTION	
	PHASE 0 FEASIBILITY STUDY (OPTIONAL)	**PHASE 1** SUBMISSION & REVIEW OF CONNECTION APPLICATION	**PHASE 2** COMPLETION OF SYSTEM IMPACT ASSESSMENT (SIA) & CUSTOMER IMPACT ASSESSMENT (CIA)	**PHASE 3** COMPLETION OF CONNECTION COST ESTIMATE (CCE)	**PHASE 4** CONNECTION APPROVAL & CONNECTION COST RECOVERY AGREEMENT (CCRA)	**PHASE 5** DESIGN & BUILD	**PHASE 6** COMMISSIONING
Duration	APPROX. 10 MONTHS	1-2 MONTHS	3-5 MONTHS	4-8 MONTHS	1+ MONTHS	1-2 YEARS	1-2 MONTHS
	Unregulated timeline	From received date	From the date the IESO issues the draft SIA	From the date the estimate agreement is executed	Longer if regulatory approvals and permits are required	Project specific (normally 1-2 years). Negotiated within CCRA	Signing of Connection Agreement
WHAT IS HAPPENING DURING THE PHASE?	The study outlines scope of work, general technical requirements and budgetary costs for you.	System Impact Assessment (SIA) Application and Customer Impact Assessment (CIA) Application	Terms and conditions of Study Agreement negotiated. Final draft SIA issued by IESO. Completion of System Impact Assessment (SIA) and CIA.	Connection Cost Estimate (CCE) must have a mutually agreed to contact (between Hydro One and you) on the work to be performed. CCE outlines your required financial contributions and construction work for the required facilities.	CCRA for project design and build. Covers customer load guarantees, cost responsibility, scope of work, project schedule and potential transfer of contestable assets following construction.	Connection requirements, standards, projects material, design, metering and milestones are completed and approved by Hydro One. Construction of your facility per IESO Market Entry Process, CCRA and OEB, provincial, and municipal organizational rules occurs.	Commissioning Involves inspection and testing of the connection facility to prepare for In-Service Date.
WHAT DO I NEED TO DO?	Provide your Account Executive all known connection information. Execute the Feasibility Study and provide payment to Hydro One. Study will not commence until you have paid in full. Make preliminary contact with First Nations and Metis communities about your project. Ensure to consult with them throughout the process, especially during public engagement consultations. PAY FOR STUDY	Complete and submit the Connection Application to both the IESO and Hydro One. Respond to questions regarding your application from IESO and Hydro One.	Review and accept (sign) the CIA Study Agreement and provide payment to Hydro One. This ensures Hydro One begins working on the CIA study. PAY FOR CIA	Provide information as required to complete the CCE Study Agreement in preparation for the actual CCE to be calculated. PAY FOR CCE Agreement	Begin milestone payments related to Connection Costs upon completion of CCRA and provide information to complete the agreement if requested by Hydro One, including decisions on Contestable work. PAY FOR Connection Costs	Build site to transmission design and construction standards, operating and maintenance standards and commissioning requirements.	Provide information to help complete the TCA. Submit Commissioning Plan for review 45 days prior to In-Service , including submission of COVER to Hydro One and IESO. Submit "As Built" Connection documents and Station Single Line Diagrams within 60 days of connection.
WHAT IS HYDRO ONE DOING?	Provides you with a Feasibility Study Agreement and connection options through the completed Feasibility Study.	Verifying that the portion of your application pertaining to Hydro One is complete and reaching agreement with you on the Scope of Work.	Provides you with a CIA Study Agreement once completed. Performs study, circulates to impacted customers. Finalizes CIA based on final SIA and comments received from impacted customers.	Provides you with the CCE Study once completed .	Hydro One provides you with your CCRA in preparation for the construction of your facility.	Procures necessary equipment, project materials, obtains necessary easements/property rights and receives necessary construction approvals and permits. Builds your connection as per the CCRA.	Finalizes TCA for execution prior to your connection. Also, notifies IESO that facilities are commissioned once complete.

IMPORTANT: The Transmission Load Connection Process takes approximately 21-36 months, however actual completion time varies significantly from project to project and is dependent on the project's complexity and required approvals, such as public consultations, permits, etc. It is highly recommended that you contact the Ministry of Energy early in the process to identify First Nation and Métis communities that should be included in public engagement or consultation activities. Regarding payments, payments to Hydro One are required at various stages (see "What Do I Need to Do?" above) in order for your application to move forward. Failure to make the required payments on time will result in delays to your application. It is the customers responsibility to ensure all of their payments are made and other requirements are met correctly as Hydro One will not be held responsible for any delays.

Important: This document is a supplement to the "Hydro One Transmission Connection Procedures" document. Customers should refer to the Procedures document, as well as the Independent Electricity System Operator's and Ontario Energy Board's Transmission Load Connection documents and processes.

FEASIBILITY STUDY: PHASE 0

A PRELIMINARY ASSESSMENT of your proposed connection is performed by Hydro One and, only if deemed necessary, an in-depth assessment known as a **FEASIBLILTY STUDY**, is completed.
A Feasibility Study is undertaken if there are potential issues with your connection relating to location, capacity, equipment, safety, resource availability or for other various reasons.

The goal of a Feasibility Study is to identify the most preferred connection option for you while also providing an estimate of the cost of your proposed connection based on the most accurate information available at the time the study is run.

The study consists of **4 steps** which are outlined below, along with your requirements as the Customer.

STEP 1 — Contact Hydro One to get started

Get started by emailing your interest to LargeAccounts@HydroOne.com—include "Tx Load Connection Inquiry" in the subject line. A Hydro One Account Executive makes initial contact with you by phone or email to discuss your application. If necessary, the Account Executive may set up a preliminary face-to-face meeting with you to further discuss the requirements of your connections and provide you with an estimate of the project cost. Should you choose to proceed with a Feasibility Study, a Feasibility Study Agreement is required.

STEP 2 — Develop cost & scope of the study

Prior to proceeding with the Feasibility Study, a Feasibility Study Agreement needs to be completed to outline the scope of work. Part of this Agreement will outline the cost to complete the Feasibility Study itself. Once the Feasibility Study has been executed by both parties, and you have provided payment to Hydro One, the actual Feasibility Study will commence. Important note: the completed date for the Feasibility Study will be negotiated between you and Hydro One as part of the Feasibility Study Agreement.

STEP 3 — Complete the study

Hydro One prepares the Feasibility Study. Once the study is completed your Hydro One Account Executive will provide it to you. The finalized study will include an estimate that is accurate to within plus or minus 50% of the actual cost of your connection as it was assessed during that specific period, and will cover the connection options examined as part of your study.

STEP 4 — Approve or Reject the study

Your Hydro One Account Executive sets up a meeting with you to review the Feasibility Study. Following the meeting you are required to choose ONE of the following options **within 45 days** of the study's completion date:

1) Accept the Feasibility Study;

2) Request a new study, which would require you to start back at step 1 or 2 (above) of the process depending on connection/project details; or

3) Withdraw your application and do not proceed any further.

Environmental Commissioner of Ontario

2014
ANNUAL ENERGY CONSERVATION PROGRESS REPORT

Planning to ~~Build~~ Conserve

APPENDIX A: ONTARIO ENERGY CONSUMPTION

The ECO is responsible for reporting on the progress of government activities related to reducing, or making more efficient use of, electricity, natural gas, propane, oil, and transportation fuels. Throughout 2013 and 2014, the government continued to place emphasis primarily on policies and initiatives to reduce Ontario's consumption of electricity (see Figure 1). However, as the following analysis highlights, electricity accounts for just over one-fifth of Ontario's total energy demand by fuel type.

Appendix A provides an update on Ontario's fuel consumption with available data derived from energy consumption data contained in the Report on Energy Supply and Demand in Canada and supplementary tables published by Statistics Canada.[191]

Methodological changes made to the data surveys that supply information to the Report on Energy Supply and Demand in Canada[192] were outlined in a previous ECO report[193] and are incorporated into the following analysis. Since the publication of the ECO's 2012 Annual Energy Conservation Progress Report, revised data were published by Statistics Canada for the 2011 calendar year.[194] This report presents updated data for 2011 and preliminary data available for 2012, and analyzes trends in Ontario's energy consumption statistics for both calendar years.

Analysis

Ontario's 2012 energy demand (based on preliminary data) was 2,405 petajoules (PJ), 4 per cent lower than demand in 2011. Figure 22 shows the breakdown of energy demand by fuel type for Ontario in 2011 and 2012. In 2012, natural gas and transportation fuels together accounted for 69 per cent of the total energy demand (about 1 per cent less than in 2011). Meanwhile, electricity accounted for approximately 20 per cent of Ontario's overall energy demand in each year. Propane, oil and other fuels[195] accounted for roughly 10 per cent of Ontario's overall demand in both 2011 and 2012. These proportional trends are virtually identical to those observed between 2007 and 2010 (see Table 15).

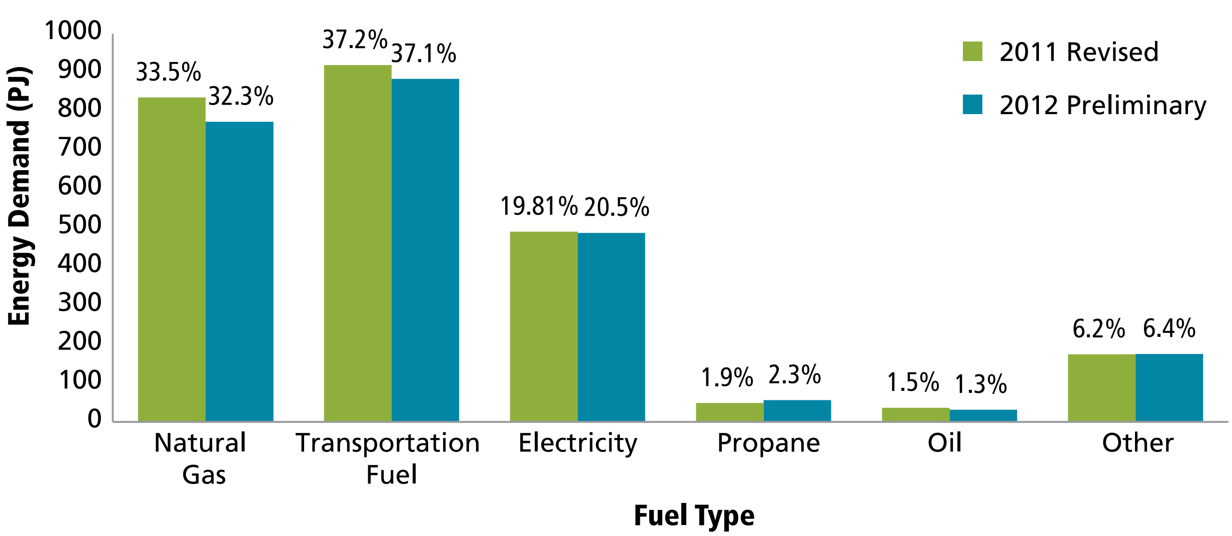


Figure 22: Ontario 2011 (revised) and 2012 (preliminary) Total Energy Demand by Fuel Type

Note: Oil demand includes kerosene and stove oil, and light fuel oil amounts; Transportation Fuel includes motor gasoline, diesel fuel oil, heavy fuel oil, aviation gasoline, and aviation turbo fuel amounts. Details of Oil and Transportation Fuels come from CANSIM table128-0016.

Source: Statistics Canada

Table 15: Annual Ontario Total Energy Demand by Fuel Type

Year	Natural Gas (PJ)	Transportation Fuel (PJ)	Electricity (PJ)	Propane (PJ)	Oil (PJ)	Other (PJ)	Total (PJ)
2007	892	909	548	40	41	192	2621
2008	884	908	586	43	34	187	2643
2009	801	897	464	38	34	152	2387
2010	776	918	480	41	34	173	2422
2011^r	837	930	495	49	36	155	2503
2012	776	893	494	56	32	156	2405

r= revised by Statistics Canada since publication in previous ECO report.

Note: all values in Table 15 incorporate methodological changes made by Statistics Canada. In the Report on Energy Supply and Demand, total energy demand for propane includes demand for the fuel for non-energy end uses (76 PJ). For all other fuels, demand for non-energy uses is not included in total energy demand amounts. The table above excludes fuel for non-energy end uses. Propane demand for non-energy uses increased in Ontario by 24 per cent between 2010 and 2012, see CANSIM table 128-0012.

Source: Statistics Canada

Ontario's 2012 total energy demand declined by 4 per cent compared to 2011 levels. Although larger in magnitude, the decline was consistent with the 0.6 per cent Canada-wide decline in energy consumption in 2012. Energy demand in Ontario decreased across all major sectors of the economy.

Transportation fuel remained the main source of energy consumed in Ontario in 2012, followed by natural gas. Although transportation fuel demand accounted for the same proportion of Ontario's total energy demand in 2012 as in 2011 (~37 per cent), total consumption of transportation fuel in Ontario declined in 2012. Almost all of Ontario's 2012 energy demand reduction was due to lower demand for transportation fuel and natural gas (-37 PJ and -61 PJ, respectively), with smaller reductions in electricity and oil demand. In its 18-Month Outlook for December 2011 to May 2013, Ontario's Independent Electricity System Operator (IESO) noted that electricity demand would be moderated by conservation efforts in 2011 and 2012 and weaker than anticipated economic growth. A decline in motor gasoline demand was the primary driver of the transportation fuel decline, likely due to ongoing improvements in vehicle fuel efficiency and record-high fuel prices in 2012.[196] This is consistent with National Energy Board projections of slowing transportation-related petroleum consumption over the next 20 years in Canada as support for electric vehicles and alternative transportation fuel grows.

Although its contribution to total fuel demand is small, Ontario's propane demand increased by approximately 14 per cent in 2012. Propane is a natural gas liquid primarily consumed for heating purposes in the commercial and residential sectors. Since 2011, higher prices for natural gas liquids relative to the price of natural gas have encouraged the development of more liquids-rich natural gas.[197] Consumption of fuels in the 'other' category remained almost constant in 2011 and 2012.

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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.

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

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 Energy Board

EB-2014-0134

Report of the Board

Demand Side Management Framework for Natural Gas Distributors (2015-2020)

December 22, 2014

Two stakeholders, both representatives of large volume customers, who did not feel that programs for large volume customers should be mandatory, recommended that the Board consider providing an opportunity for large volume customers to "opt-out" from, or not be required to help fund, a gas utility DSM program for large volume customers. They noted that the principle that ratepayer funded DSM should not be mandatory for large volume customers protects large volume customers as a class, but does not address a customer-specific issue where it was argued that many of these customers are self-motivated and have made significant energy efficiency investments on their own. These stakeholders noted that large volume customers do not need or desire a mandatory ratepayer funded DSM program and that in the event a customer believes that utility or third party expertise is helpful, that be provided outside of a rate funded DSM program.

6.2 Board Conclusions

As discussed in Section 4.2 – Budgets, the Board expects the gas utilities' multi-year DSM plans will enable the delivery of results in the areas which have been identified as key priorities in the LTEP, Conservation Directive and by the Board.

Key priorities identified in the LTEP and Conservation Directive:

a) Implement DSM programs that can help reduce and/or defer future infrastructure investments;

b) development of new and innovative programs, including flexibility to allow for on-bill financing options;

c) increase collaboration and integration of natural gas DSM programs and electricity CDM programs; and

d) expand the delivery of low-income offerings across the province.

The Board identified priorities:

e) implement DSM programs that are evidence-based and rely on detailed customer data; and,

f) ensure that programs take a holistic-approach and identify and target all energy saving opportunities throughout a customer's home or business.

It is important that the gas utilities' multi-year DSM plans focus on activities that will achieve a greater amount of long-term natural gas savings, better help participating customers manage their overall usage and ultimately their bills, and consider the guiding principles from Section xx and key priorities outlined above. The Board has provided a specific discussion of program types in the DSM Guidelines in Section 6.0. The gas utilities are expected to collaborate and integrate natural gas DSM program offerings across all sectors with Province-Wide Distributor and/or Local Distributor CDM programs throughout the course of the DSM framework period. As part of the multi-year DSM plans filed by the gas utilities, the Board expects that the gas utilities will include a discussion of the areas where programs have been coordinated and/or integrated with Province-Wide Distributor and/or Local Distributor, program aspects that have the potential to be integrated in the future and any barriers that have restricted the program from being coordinated and integrated with an electricity CDM program.

Additionally, the gas utilities DSM portfolios should include programs that are specifically designed to address customer groups with significant barriers to entry (e.g., small business customers). DSM portfolios should also include programs targeted to customers who are already very invested in energy efficiency and where more complex or customer-specific options are necessary.

The Board is of the view that rate funded DSM programs for large volume customers should not be mandated as these customers are sophisticated and typically competitively motivated to ensure their systems are efficient. The small number of customers in these classes further heightens the issues of one customer subsidizing business improvements of another. If a gas utility, in consultation with its large volume customers, determines that there is substantial interest in the gas utility providing expertise and a value-added service to help improve the energy efficiency levels of these customers' facilities, the gas utilities are able to propose a fee-for-service program which the Board will approve on its merits. The primary focus of any program proposed for large volume customers should be offering technical expertise, including conducting facility audits, advice for operational improvements, or engineering studies as opposed to capital incentives. Specifically, the gas utilities can propose a fee-for-service DSM programs to the customers in those classes identified as large volume rate classes in the table below. As can be seen in the table below, there is a very limited number of customers in these rate classes.

Table 1 – Large Volume Rate Classes

Enbridge Gas Distribution Inc.				
Rate Class	No. of Customers	2013 Annual Volumes (m^3)[22]	Percent of Total Annual Volumes[21]	Description of Rate Class
Rate 125	5	n/a	n/a	For applicants who use the EGD network to transport a specified maximum daily volume of natural gas that is not less than 600,000 m^3.

Union Gas Limited				
Rate Class	No. of Customers[23]	2013 Annual Volumes (m^3)[24]	Percent of Total Annual Volumes	Description of Rate Class
Rate T1	38	452,838,193	3%	Rate T1 is a contract rate for customers in Union's southern operations area who actively manage their own storage services, have an aggregated Firm Daily Contracted Demand up to 140,870 m3 and who consume a minimum of 2.5 million m^3 of natural gas each year. Customers in this rate class include manufacturing plants, chemical plants, large food processors/greenhouses and small specialty steel plants.
Rate T2	22	4,241,475,463	30%	Rate T2 is a contract rate for customers in Union's southern operations area who actively manage their own storage services and require a minimum aggregated Firm Daily Contract Demand of at least 140,870 m^3. Customers in this class include large power (cogeneration), large steel, large petrochemical plants and a large feedstock plant.
Rate 100	14	1,926,579,498	14%	For large commercial and industrial customers who have signed a Northern Distribution contract for firm natural gas delivery with Union Gas. These customers are typically large manufacturers requiring a very large volume of natural gas for industrial processes – such as steel, pulp and paper and mining. These customers, located in our northern and eastern operation areas, require a minimum consumption of 100,000 m3 of natural gas or more each day. These customers must maintain a 70% load factor over the course of a year.

The fee-for-service program would be different than the current large volume program approved by the Board. Rate funding recoverable from all customers in the large

[22] Rate 125 is made up of power generators who are billed on contract demand as opposed to actual throughput.
[23] As per EB-2014-0145, Exhibit A, Tab 2, Appendix A, Schedule 10
[24] As per EB-2014-0145, Exhibit A, Tab 2, Appendix A, Schedule 6

volume rate classes for a fee-for-service program can only be used for portfolio level administration costs, restricted to utility staff, marketing and evaluation activities. Any additional funding to support customer-specific deliverables, including facility audits, engineering reports or technology upgrades would need to be provided directly from the participating customer. The gas utilities may charge interested customers an appropriate fee to recover the cost of the energy efficiency consulting service it can provide. The Board expects that the gas utilities, with many years delivering DSM programs and an established expertise, as well an experienced DSM staff, can operate at a highly efficient level to source and acquire the opportunities available. In order to motivate the gas utilities to seek out these possibilities, the Board will enable the gas utilities to claim the verified gas savings that result from the fee-for-service large volume program. Achievement of the targets in these areas may result in a performance incentive. The performance incentive earned in relation to the fee-for-service large volume program will be recovered in the same manner as the gas utilities have traditionally recovered amounts. The Board feels that this approach strikes an appropriate balance by substantially reducing the cross-subsidization issues of large volume customers given the relatively small number of customers in the rate classes while maintaining the potential for considerable natural gas savings from large volume customers.

7.0 PROGRAM EVALUATION

Evaluation, Measurement and Verification (“EM&V”) is the process of undertaking studies and activities aimed at assessing the impacts (e.g., natural gas savings) and effectiveness of an energy efficiency program on its participants and/or the market. Monitoring and EM&V also provides the opportunity to identify ways in which a program can be changed or refined to improve its performance. It is important to ensure proper EM&V studies are being undertaken to enable the pursuit of cost-effective DSM programs. Moreover, EM&V of DSM activities is important to support the Board’s review and approval of prudent DSM spending, and requests to recover lost revenues and shareholder incentive amounts claimed by the gas utilities.

Traditionally, the evaluation process related to DSM programs has been a function that the gas utilities have managed, with input from key stakeholders included throughout the process. The Board sought stakeholder comment related to the Board taking on a larger role in the program evaluation process.

7.1 Stakeholder Comments

Both Enbridge and Union supported the Board's recommended position and noted that they would work collaboratively with the Board to ensure that final results from the evaluation process were reliable.

Most stakeholders did not support the Board's recommended approach to taking on a larger role in the program evaluation process. Some stakeholders questioned the appropriateness of the Board being involved in the process prior to the completion of evaluations and final results being filed. Other stakeholders did not feel it necessary for the Board to be involved in the process, noting that the process is one which has evolved over the course of a number of years and has developed into a robust, cooperative and technical process that has produced good, reliable results on a consistent basis.

7.2 Board Conclusions

The Board is of the view that it is in the best position to coordinate the evaluation process throughout the DSM framework period (i.e., 2015 to 2020). A process coordinated by the Board, in collaboration with the gas utilities, and supported by stakeholders with technical expertise, will be one that results in a thorough evaluation of DSM programs in an efficient manner.

By taking on a larger role in the EM&V process, the Board will consult and seek expert opinion from both the gas utilities and stakeholders as appropriate. In addition, the Board expects to provide input on evaluation methodologies and help ensure that the operational characteristics of the programs will generate the data required to undertake robust and accurate evaluations. The Board will contribute in the annual evaluation process to confirm that the program impacts have been appropriately identified and to verify that programs have resulted in the intended benefits and to inform future program design and delivery.

In addition to the annual evaluations of program results, which will be published every year, the Board will conduct multi-year impact assessments of selective gas utility DSM programs on a periodic basis (e.g., every three years). The impact assessments will analyze program data which span multiple program years and investigate the success and actual effects of the programs in the marketplace, looking at areas such as whether energy efficiency measures were actually installed, stayed installed and if they have had the intended effect of reducing overall consumption levels. These periodic assessments will not have retroactive impacts and will not be related to the annual evaluation and audit process, rather, they may be used to help inform and assist the gas utilities' future program design and delivery.

The results from the DSM program evaluations are expected to feed back to the screening and evaluation process of DSM programs by taking into account the free ridership rates, spillover effects, attribution of benefits and persistence of savings. The technical details of these adjustment factors are discussed in greater detail in the DSM Guidelines in Section 7.0.

8.0 INPUT ASSUMPTIONS

In order to effectively estimate the amount of energy savings achieved through the delivery and implementation of DSM programs, the gas utilities rely on a set of approved engineering assumptions that represent the best available information regarding various characteristics of an energy efficient technology (e.g., life cycle, energy usage level, gas savings, etc.). Energy efficiency assumptions are included in the calculations conducted by gas utilities to determine which programs produce more benefits (amount of dollars avoided that would have been needed to purchase natural gas had the DSM program not be active) than costs (the cost of the DSM program). When benefits are greater than costs, a program is deemed to be cost-effective.

In the Draft Report, the Board sought comments from stakeholders on increasing its role with respect to developing and updating natural gas DSM input assumptions. The Board proposed to coordinate the process of annually updating the common list of input assumptions.

8.1 Stakeholder Comments

The gas utilities were supportive of the Board participating and leading the coordination of the annual process to update the common list of input assumptions. The gas utilities offered to provide support where the Board determined it necessary and appropriate. Most stakeholders were generally less supportive of the Board taking a more active role in annually updating the list of input assumptions. These stakeholders noted that the current process is effective. The process that resulted from the 2012-2014 multi-year DSM plans requires periodic meetings of a small team made up of gas utility representatives, key stakeholders and third party experts to discuss, propose, test and reach consensus on required and appropriate updates to the input assumptions list. The final updates are annually presented to the Board through an application by the gas utilities.

8.2 Board Conclusions

The Board will increase its role and coordinate the process of annually updating the list of natural gas input assumptions. The Board will ensure that an appropriate process is developed that includes the gas utilities, external experts and key stakeholder involvement, ensuring objective, evidence-based updates are applied to the list of input assumptions. The list of input assumptions provides confidence in both the cost effectiveness screening and final evaluation results where assumptions are required. The Board will evaluate where it is appropriate to align the natural gas DSM input assumption list with the electricity CDM input assumptions list to enable the greatest amount of collaboration and integration of both natural gas DSM and electricity CDM programs. The Board's role will align with its mandate to work in the public interest for such an important component of the DSM framework. Technical details of how the Board proposes to undertake annually updating the input assumptions list are included in the DSM Guidelines in Section 8.0.

9.0 COST-EFFECTIVENESS SCREENING

In order to determine which DSM programs should continue as part of the gas utilities' DSM plans, the gas utilities assess their programs using a process to calculate and test the cost-effectiveness of delivering a program. As part of the Draft Report, the Board sought stakeholder comment on the appropriateness of using the Total Resource Cost ("TRC") test and Program Administrator Cost ("PAC") test to calculate cost-effectiveness and screen potential DSM programs.

The TRC test measures the energy related benefits and costs of DSM programs experienced by both the gas utility system and program participant for as long as those benefits and costs persist. The PAC test measures the gas utilities' avoided costs and the costs of DSM programs experienced by the gas utility system. The Board suggested that the TRC test be used as the primary cost-effectiveness test and that the gas utilities can use the PAC test as a secondary reference tool, assisting with prioritizing which programs deliver the most effective results.

9.1 Stakeholder Comments

Almost all stakeholders shared the same view that the gas utilities should use a more robust test than the TRC test. Many stakeholders noted that the traditional TRC test does not appropriately account for and quantify the additional DSM program benefits, such as non-energy benefits, including environmental benefits, societal benefits, utility benefits and other participant benefits (e.g., improving comfort, increased property value, amongst others). Many stakeholders recommended the Board either include non-energy benefits as part of the TRC test calculation or adopt the Societal Cost ("SC") test as the primary cost-effectiveness screening test. The SC test quantifies and values additional benefits outside of only the avoided natural gas supply costs which are considered in the TRC test. Stakeholders recommended that both the TRC and PAC tests be used as secondary reference tools to provide a better understanding of the cost-effective of each potential DSM program.

Some stakeholders also suggested that the cost-effectiveness threshold for low-income program offerings be lowered from the current threshold of 0.7 to ensure that the gas utilities do not miss any opportunities to achieve natural gas savings and deliver valuable programs to low-income customers.

9.2 Board Conclusions

On October 23, 2014, the Minister of Energy amended his Conservation First directive to the OPA and made it mandatory that electricity distributor CDM programs are screened using the TRC test and "include a 15% adder to account for the non-energy benefits associated with the electricity CDM programs, such as environmental, economic and social benefits." To effectively align natural gas DSM programs with electricity CDM programs and take into consideration government objectives outlined in the Conservation Directive to the OPA, the Board has concluded that the same approach should be used for screening DSM programs.

The Board will adopt an enhanced TRC test, or the "TRC-Plus" test, which the gas utilities should use to screen all potential DSM programs when developing their multi-year DSM plans. The gas utilities should directly apply a 15% non-energy benefit adder to the benefit side of the TRC test calculation. The gas utilities are able to apply for approval of low-income programs with cost-effectiveness results lower than the current 0.7 threshold using the TRC-Plus test. These programs will be approved on their merits.

The gas utilities should also incorporate the PAC test as a secondary cost-effectiveness reference tool to help better inform which programs should be proposed. The gas utilities should include all the available cost-effectiveness test results for each proposed program in their multi-year DSM plan applications. Technical details of DSM program screening, including the TRC-Plus and PAC test calculations are outlined in Section 9.0 of the DSM Guidelines.

10.0 AVOIDED SUPPLY COSTS

Successful implementation of DSM programs should ultimately lead to the gas utilities avoiding costs related to not having to purchase, or provide, an extra unit of natural gas. Avoided costs will also result from reduced demand for other resources such as electricity, heating fuel oil, propane or water through DSM programs. Avoided supply costs should be a consideration when conducting cost effectiveness calculations of potential DSM programs. As outlined in Section 13 below, the gas utilities should discuss how they consider avoided supply costs when conducting their infrastructure planning for future capital projects. Details are provided within the DSM Guidelines in Section 10.0.

11.0 DEFERRAL AND VARIANCE ACCOUNTS: RECOVERY AND DISPOSITION OF DSM AMOUNTS

The Conservation Directive requires the Board to have regard to ensuring that lost revenues are not a disincentive to the gas utilities for undertaking DSM activities. The Board will continue with a Lost Revenue Adjustment Mechanism Variance Account for this purpose. Details of this account and other DSM deferral and variance accounts are documented in Section 11.0 of the DSM Guidelines.

12.0 INTEGRATION & COORDINATION OF NATURAL GAS DSM AND ELECTRICITY CDM PROGRAMS

The natural gas utilities should pursue coordinated and integrated programs with electricity distributors and/or the OPA to achieve efficiencies and convenient, integrated programs for customers. Combining efforts in key program areas should allow greater possibilities for an increase in total combined energy savings and reduced program delivery and administration costs.

Coordination usually takes place at the design stage of a program whereas integration is typically done at the delivery stage of the program. Coordination efforts should ensure, amongst other things, consistent program design including areas such as definition of goals, customer screening criteria, marketing, training, customer rebates and metrics. Integration should normally achieve consistency in delivery services of a program, which in most instances will result in a delivery agent providing both electricity and natural gas offerings to a customer at the same time.

The Board expects that coordinated and integrated energy conservation and energy efficiency programs are a primary consideration when the gas utilities are designing and developing all program offerings. The Board is of the view that this will ensure the efficient use of program costs, enhance the reach of all programs to a greater number of customers, ensure that customers receive the same information regarding energy conservation and energy efficiency upgrades, achieve efficiencies in customer participation and allow for greater possibilities to transform the market.

Some strategic program areas that may be beneficial for the gas utilities to pursue coordinated and integrated efforts with electricity CDM programs include the design and delivery of low-income and market transformation programs, mass market programs, and home/building retrofits that will result in long-term savings. These are examples of programs that can benefit from consistent messaging and program details. Another example where coordination is beneficial is with respect to the input assumptions list. Ensuring that both gas utilities and electricity distributors are using the same set of assumptions will allow program benefits to be calculated consistently and shared following collaborative program efforts.

As a result of the intended benefits discussed above, the Board expects that the gas utilities will provide specific evidence showing how the elements of each of their proposed programs can be integrated with electricity CDM programs and coordinated with electricity distributors and/or the OPA. For consistency purposes, the Board will liaise with the OPA to address integrating and coordinating electricity CDM programs with natural gas DSM programs and govern the gas utilities future DSM offerings accordingly.

13.0 FUTURE INFRASTRUCTURE PLANNING ACTIVITIES

As part of all applications for leave to construct future infrastructure projects, the gas utilities must provide evidence of how DSM has been considered as an alternative at the preliminary stage of project development.

In order for the gas utilities to fully assess future distribution and transmission system needs, and to appropriately serve their customers in the most reliable and cost-effective manner, the Board is of the view that DSM should be considered when developing both regional and local infrastructure plans. This is consistent with the direction outlined in the LTEP and the Conservation Directive, which state that the Board shall take steps it considers appropriate towards implementing the government's policy of putting conservation first in electricity distributor and gas distributor infrastructure planning processes at the regional and local levels, where cost-effective and consistent with maintaining appropriate levels of reliability. The Board expects the gas utilities to consider the role of DSM in reducing and/or deferring future infrastructure investments far enough in advance of the infrastructure replacement or upgrade so that DSM can reasonably be considered as a possible alternative. If a gas utility identifies DSM as a practical alternative to a future infrastructure investment project, it may apply to the Board for incremental funds to administer a specific DSM program in that area where a system constraint has been identified.

The Board is also of the view that the gas utilities should each conduct a study, completed as soon as possible and no later than in time to inform the mid-term review of the DSM framework. The studies should be based on a consistent methodology to determine the appropriate role that DSM may serve in future system planning efforts. As part of the multi-year DSM plan applications, the gas utilities should include a preliminary scope of the study it plans to conduct and propose a preliminary transition plan that outlines how the gas utility plans to begin to include DSM as part of its future infrastructure planning efforts.

14.0 STAKEHOLDER CONSULTATION

Consistent with the Board’s consumer-centric approach, the gas utilities are expected to engage their stakeholders and conduct meaningful consultations to gather input and feedback on prospective DSM programs and other relevant areas of their multi-year DSM plans. The Board will not mandate the nature of this consultation, but will expect details to be provided in any application for approval of multi-year DSM plans.
The Board has outlined various options earlier in this report where its involvement in various functions related to the DSM framework will be expanded. Although the Board’s role will be increased, primarily with respect to oversight related to the evaluation process and annual updates to the input assumptions list, the Board continues to see the direct involvement of all key stakeholders, notably the gas utilities and intervenors with the required expertise, to be critical and necessary to ensure all elements of the gas utilities’ multi-year DSM plans are considered during the program development, approval and evaluation stages.

15.0 IMPLEMENTATION AND TRANSITION

Implementing a new multi-year DSM plan will require sufficient time for the gas utilities to consider the direction provided in this framework and fully develop their overall portfolio and specific programs. The Board wants to ensure that the multi-year DSM plan applications that are submitted by the gas utilities are robust and that the companies have been afforded a reasonable amount of time to develop an internal strategy, consult with stakeholders and prepare a meaningful multi-year DSM plan for the Board to consider. The Board provides guidance below regarding the timelines related to the development and filing of the gas utilities' new multi-year DSM plans.

15.1 DSM Activities in 2015

The gas utilities should roll-forward their 2014 DSM plans, including all programs and parameters (i.e., budget, targets, incentive structure) into 2015. Both Enbridge and Union requested that their 2014 activities be rolled-forward into 2015 to help facilitate a smooth evolution into the new DSM framework.

The Board agrees this is appropriate and will allow the gas utilities to fully consider the new DSM framework and appropriately develop their DSM portfolio and suite of programs that will make up their new multi-year plans. The gas utilities should increase their budgets, targets and shareholder incentive amounts in the same manner as they have done throughout the current DSM framework (i.e., 2013 updates to 2014 should now apply as 2014 updates to 2015). The Board expects the gas utilities' new multi-year DSM plans will fully address the guiding principles and key priorities outlined in the framework.

Currently, DSM amounts have already been approved and are included in rates for both Enbridge and Union[25]. If necessary, the gas utilities may modify their current suite of programs and re-allocate funds between approved programs up to a maximum of 30% of the approved annual DSM budget for an individual DSM program. Additionally, the gas utilities may increase overall spending by up to 15%, consistent with the Board's guidance as part of the gas utilities' current, approved DSM plans, and use these additional funds to begin to incorporate and address the guiding principles and key priorities outlined in the DSM framework. If a gas utility incurs DSM spending greater than that which has been previously approved, it should track these expenditures in the DSM variance account for clearance in a future proceeding.

15.2 Multi-Year DSM Plan Applications

[25] 2015 DSM amounts were approved by the Board as part of EGD's 2014-2018 Custom IR Rate Application (EB-2012-0459). EGD has subsequently updated its 2015 DSM budget amounts as part of its 2015 rate application (EB-2014-0276). 2015 DSM amounts were approved by the Board as part of Union's 2014-2018 rate application, EB-2013-0202. Union has subsequently updated its 2015 DSM budget amounts as part of its 2015 rate application (EB-2014-0271).

The Board expects that the gas utilities will file complete multi-year DSM plans that provide the proposed details of their DSM activities between 2015 and 2020 on or before April 1, 2015. The gas utilities should coordinate the filing of their multi-year DSM plans so they are submitted at or around the same time. The Board expects to hear the two applications in a combined proceeding due to the similar nature of the requests, the importance of regulatory efficiency and to respect resource constraints many parties are operating within, including the Board, intervenors, and the gas utilities.

Further details, including the information the gas utilities are required to include with any application are included in the DSM Guidelines at Section 14.1.

APPENDIX A – Summary of Board Conclusions[26]

SECTION - #	BOARD CONCLUSIONS
TARGETS – 3.0	The gas utilities should develop and propose both annual performance targets (natural gas savings and other appropriate program-activity related metrics, included within annual weighted scorecards) as well as longer-term natural gas savings targets to be met by December 31, 2020.
BUDGETS – 4.0	The gas utilities' annual DSM budgets should be guided by the principle that DSM costs (inclusive of both DSM budget amounts and shareholder incentive amounts) for a typical residential customer of each gas utility should be $2.00/month. Based on a $2.00/month cost impact to a typical residential customer and considering the general historic program mix and the relative size of each utility, the Board has estimated total annual DSM amounts may reach $85M for Enbridge and $70M for Union (these amounts are inclusive of the maximum annual shareholder incentive). The budget guidance for the new multi-year DSM plans is in the order of double the cost impacts to residential customers from the 2012 to 2014 DSM period.
SHAREHOLDER INCENTIVE – 5.0	The Board will make an annual shareholder incentive available to both Enbridge and Union that is equal to a total annual maximum of $10.45 million. The incentive amount available will not increase or decrease relative to approved DSM budgets, and is not to be increased annually for inflation. If NRG files a DSM plan with the Board, the Board will provide details on available shareholder incentive amounts at that time. The shareholder incentive for NRG will be commensurate with its targeted level of achievement and proportional to its size relative to EGD and Union. The Board will also make a cost-efficiency incentive available. In the event that a gas utility is able to meet all of its annual natural gas savings targets (i.e., 100% in all natural gas savings scorecard metrics), the gas utility may choose to roll-forward and use any remaining approved DSM budget amounts to be used in the following year with no subsequent impact on the approved targets for the following year. There will be no impact on future year targets if the cost-efficiency incentive is earned.
PROGRAM TYPES – 6.0	The gas utilities' multi-year DSM plans should enable the delivery of results in the areas which have been identified as key priorities in the LTEP, Conservation Directive and by the Board (Section 4.2). It is important that the gas utilities' multi-year DSM plans focus on activities that will achieve a greater amount of long-term natural gas savings, better help participating customers manage their overall usage and ultimately their bills, and consider the guiding principles (Section 2). The Board is of the view that rate funded DSM programs for large volume customers should not be mandated. If a gas utility, in consultation with its large volume customers, determines that there is substantial interest in the gas utility providing expertise and a value-added service to help improve the energy efficiency levels of these customers' facilities, the gas utilities are able to propose a fee-for-service program which the Board will approve on its merits. The primary focus of any program proposed for large volume customers should be offering technical expertise, including conducting facility audits, advice for operational improvements, or engineering studies as opposed to capital incentives. Specifically, the gas utilities can propose a fee-for-service DSM programs to the customers in rate classes identified as large volume rate classes (EGD: Rate 125; Union: Rate T1, Rate T2, Rate 100). Under this type of program, ratepayer funding will only be used to provide recovery for administrative related costs (e.g., utility staff, overheads, evaluation, etc.) and any shareholder incentive amounts earned. Any additional energy efficiency consulting services, audit reports and capital investments must be

[26] These conclusions are a high-level summary of those provided in detail throughout the body of the DSM framework above. To ensure proper context and guidance is provided, please refer to the detailed sections above.

SECTION - #	BOARD CONCLUSIONS
	provided by the participating customers directly. The gas utilities may charge interested customers an appropriate fee to recover the cost of the energy efficiency consulting service it can provide. In order to motivate the gas utilities to seek out these possibilities, the Board will enable the gas utilities to claim the verified gas savings that result from the fee-for-service large volume program. Achievement of the targets in these areas may result in a performance incentive. The performance incentive earned in relation to the fee-for-service large volume program will be recovered in the same manner as the gas utilities have traditionally recovered amounts.
PROGRAM EVALUATION – 7.0	The Board will coordinate the evaluation process throughout the DSM framework period (i.e., 2015 to 2020). The Board, in collaboration with the gas utilities, and with the technical expertise and support of stakeholders, will ensure results are continued to be produced in a thorough and efficient manner. The Board expects to provide input on evaluation methodologies and help ensure that the operational characteristics considered will generate the data required to undertake robust and accurate evaluations.
INPUT ASSUMPTIONS – 8.0	The Board will increase its role and coordinate the process of annually updating the list of natural gas input assumptions. The Board will ensure that an appropriate process is developed that includes the gas utilities, external experts and key stakeholder involvement, ensuring objective, evidence-based updates are applied to the list of input assumptions. The Board will evaluate where it is appropriate to align the natural gas DSM input assumption list with the electricity CDM input assumptions list to enable the greatest amount of collaboration and integration of both natural gas DSM and electricity CDM programs.
COST EFFECTIVENESS SCREENING – 9.0	The Board will adopt an enhanced TRC test, or the "TRC-Plus" test, which the gas utilities should use to screen all potential DSM programs when developing their multi-year DSM plans. The gas utilities should directly apply a 15% non-energy benefit adder to the benefit side of the TRC test calculation. The gas utilities are able to apply for approval of low-income programs with cost-effectiveness results lower than the current 0.7 threshold. These programs will be approved on their merits. The gas utilities should also incorporate the PAC test as a secondary cost-effectiveness reference tool to help better inform which programs should be proposed. The gas utilities should include all the available cost-effectiveness test results for each proposed program in their multi-year DSM plan applications.
INTEGRATION & CO-ORDINATION WITH CDM – 12.0	The natural gas utilities should pursue coordinated and integrated programs with electricity distributors and/or the OPA to achieve efficiencies and convenient, integrated programs for customers. The Board expects that coordinated and integrated energy conservation and energy efficiency programs are a primary consideration when the gas utilities are designing and developing all program offerings. The Board expects that the gas utilities will provide specific evidence showing how the elements of each of their proposed programs can be integrated with electricity CDM programs and coordinated with electricity distributors and/or the OPA.
FUTURE INFRASTRUCTURE PLANNING – 13.0	As part of all applications for leave to construct future infrastructure projects, the gas utilities must provide evidence of how DSM has been considered as an alternative at the preliminary stage of project development. The Board is of the view that DSM should be considered when developing both regional and local infrastructure plans. The Board expects the gas utilities to consider the role of DSM in reducing and/or deferring future infrastructure investments far enough in advance of the infrastructure replacement or upgrade so that DSM can reasonably be considered as a possible alternative. If a gas utility identifies DSM as a practical alternative to a future infrastructure investment project, it may apply to the Board for incremental funds to administer a specific DSM program. The Board is also of the view that the gas utilities should each conduct a study, completed as soon as possible and no later than in time to inform the mid-term review of the DSM framework. The studies should be based on a consistent methodology to determine the appropriate role that DSM may serve in future system planning efforts.

APPENDIX B: ON-BILL FINANCING

Union has considered the flexibility given by the Board in Section 6.2 of the Framework for the "development of new and innovative programs, including flexibility to allow for on bill financing options". On-bill financing was discussed as a potential new program idea in a consultation session with stakeholders in December 2013 as referenced at Exhibit A, Tab 3, Appendix B and the majority of participants did not support moving ahead with this new offering.

One of the guiding principles for the DSM Framework is that programs should be designed to remove barriers in the marketplace to increase program take-up[1]. Customer research provides important insights on the barriers to participation. Notably, customers do not cite access to financing as an obstacle to undertaking energy efficiency improvements.

High upfront costs of undertaking energy efficiency improvements are a commonly cited barrier to participating in DSM programs. While some may argue that an on-bill financing program helps to overcome upfront costs, it would only do so if the customer is willing to take on additional debt. Union's research suggests that there is a wide array of financing options available to those customers wishing to pursue financing for energy efficiency improvements, including some borrowing vehicles which specifically target energy efficiency improvements[2]. In spite of the current availability of financing, the majority who have or expect to undertake

[1] EB-2014-0134 Report of the Board, December 22, 2014, page 8.
[2] On-Bill Financing for DSM Programs: Research Insights and Findings.

energy efficiency improvements in the next two years have or expect to do so from cash or savings[3]. Union believes that making an additional borrowing vehicle available through an on-bill financing program, with additional customer costs required to establish that vehicle, will not alter the customer's willingness to take on debt for energy efficiency improvements.

In Union's view, overcoming the upfront cost of energy efficiency improvements is critically linked to two factors:

1. ***Customer incentives***

   Union has heard that rebates and incentives are the most valued program feature by residential single family and commercial/industrial mass market customers. In contrast, access to financing options is perceived as the least valuable program feature by the majority of these customers.

2. ***Customer understanding of the potential to save on their utility bills***

   Lack of clarity on savings also emerges as a barrier. Union believes that program features that build customer understanding of the benefits of the investment, such as the energy assessment component of the Home Reno Rebate Offering outlined at Exhibit A, Tab 3, Appendix A, Section 1.0 will be far more effective in encouraging customers to implement efficiency upgrades than an on-bill financing offering.

[3] On-Bill Financing for DSM Programs: Research Insights and Findings.

In order to ensure customers have an understanding of the financing options available to them during the 2015-2020 Plan, Union intends to focus on enabling financing options through the following:

- Providing information to customers on financing options for energy efficiency upgrades, for example within a promotion on a bill insert
- Initiating dialogue with key financial institutions about how their financing offerings might be promoted from Union's programs
- Developing an online page on Union's website that provides customers with financing information and options

A Spectra Energy Company

On-Bill Financing for DSM Programs:

Research Insights and Findings

Prepared by: Market Research & Analysis

April 2014

2013 Residential Market Penetration Survey

Section VI: On-Bill Financing & Energy Conservation Behaviours, Actions & Intentions

E01.

Boomers, those aged 55-64 are the most likely to have done something to reduce the amount of energy their house uses. Conversely those less than 35 and those 65+ are the least likely to have done something to reduce the amount of energy their house uses. No significant differences are apparent by income, or household size.

E01. Over the past five years, have you completed any projects to reduce the amount of natural gas or electricity your home uses?	% of Total n=1,200
Yes	40%
No	58%
DK/NS/REF	1%

E02.

Deep energy efficiency measures such as basement wall insulation are less likely to have been installed compared to less costly 'shallow' measures such as adding weather stripping. This tendency is consistent across all customer groups.

E02. Which of the following projects did you do within the past five years?	% of Total (Base: Those that have completed a project in the past five years) n=480
Switch to Energy Efficient Lighting (CFLs, 'twisty' bulbs, LED)	62%
Add Weather stripping or caulking to doors and/or windows	51%
Replace Windows	47%
Replace heating equipment / furnace	43%
Replace water heater	41%
Replace appliances	37%
Attic insulation	32%
Basement wall insulation	30%
Replace cooling equipment / Air Conditioning	24%
Exterior wall insulation	23%
Air sealing/ duct sealing	20%
Something Else	14%

E03A – E03C

Savings (66%) is the dominant vehicle to fund energy efficient home improvements across all single family customers. Over half (59%) have spent at least $5,000 on energy efficient improvements to their home over the past five years, 31% have spent at least $10,000. As expected, those households with the highest incomes are more likely to have spent at least $10,000. (23% of those with a HH income < $80,000 spent at least $10,000 vs. 39% of those with a HH income >= $80,000). Unlike the Toronto quant study, 'getting the home ready for sale' was not a common reason for making energy efficient improvements. Instead, 'saving money on energy bills' (43%) and to 'replace old or broken equipment' (28%) were the most common reasons.

E03a. How did you pay for these improvements? Was it primarily through...?	% of Total (Base: Those that have completed a project in the past five years) n=446
Savings/Cash	66%
A Line of Credit	9%
A Credit Card	6%
A Mortgage/Home equity loan	3%
A Personal Loan from a Financial Institution	2%
Or Some other way	6%
DK/NS/REF	8%

E03b. Approximately how much would you say you have spent on home improvements or upgrades specifically to improve the energy efficiency of your home in the past five years?	% of Total (Base: Those that have completed a project in the past five years, excluding DK/NS/REF) n=480
Less than $1,000	15%
$1,000 to under $5,000	26%
$5,000 to under $10,000	28%
$10,000 or more	31%

E03c. Why did you make these energy efficiency improvements to your home?	% of Total (Base: Those that have completed a project in the past five years) n=480
To save money on energy bills	43%
To replace or upgrade old or broken equipment	28%
To conserve energy	16%
To improve the comfort of my home	15%
To help protect the environment	7%
To improve the look of the home	6%
To increase the value of my home	5%
To prepare the house for sale	1%
Other	19%

E04A – E03C, E05

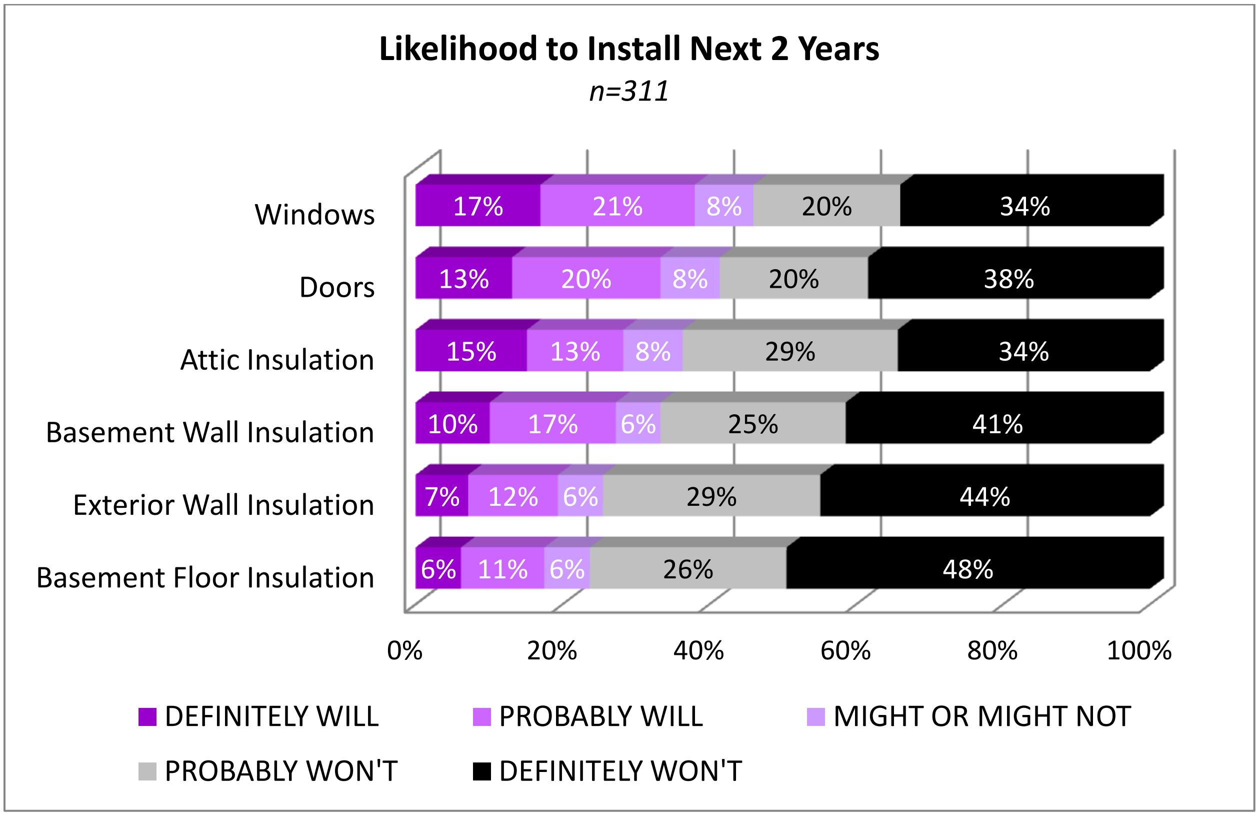
The majority of customers (71%) have no plans to make their home more energy efficient in the next two years. This is consistent with customer sentiment since at least 2011. The most cited reasons are that the 'home is already energy efficient' (51%) and that they 'do not have the money' (18%). Interestingly the 'hassle' factor and uncertainty surrounding the selection of a contractor were not common mentions, though they were cited factors in a review of other sources. Lack of financing was not cited as a reason by any customers.

Among the minority of customers (26%) planning to make their home more energy efficient in the next two years, most plan to fund it through savings (61%) with windows and doors being the most likely (aided) mentions. Not surprisingly, the intention to make the home more energy efficient decreases with age.

E04a. Do you have any plans to make your home more energy efficient within the next two years?	% of Total n=1,200
Yes	26%
No	71%
DK/NS/REF/Undecided	3%

E05. Why do you say that?	% of Total (Base: Those that have NO plans to make their home more energy efficient in the next two years) n=889
Home is already efficient	51%
Don't have the money/savings/too expensive/cost too much	18%
Have other more pressing priorities	4%
Lack of awareness/unsure about the energy efficient changes that could be made	2%
Too much hassle/would cause too much disruption	2%
Don't have the time	2%
Concerned about the quality of the work/finding the right supplier/contractor	1%
Would not make a substantial enough reduction on utility bills	1%
Don't have the financing/no loan/refused for a loan	0%
Other	19%

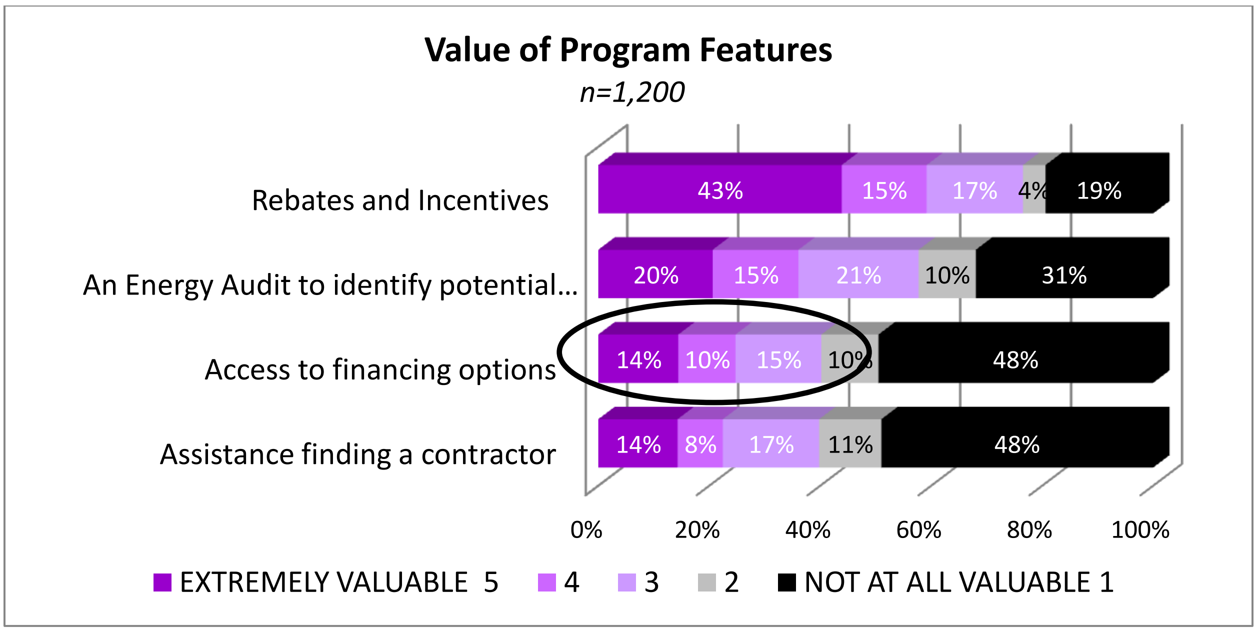
E04c. How are you planning to pay for these energy efficiency improvements? Would that be primarily with…?	% of Total (Base: Those that have plans to make their home more energy efficient in the next two years but not any of the options mentioned in E04b) n=266
Savings/Cash	61%
A Line of Credit	13%
A Personal Loan from a Financial Institution	2%
A Mortgage/Home equity loan	1%
A Credit Card	6%
Or Some other way	7%
DK/NS/REF/Undecided	9%



E06

Rebates and incentives are the clearly preferred program feature among customers; with 57% indicating that they are Valuable. The value of rebates and incentives is markedly lower among seniors (44% vs. 57% Total). Only 24% indicated access to financing options as valuable. Those customers with the highest incomes were least likely to describe access to financing options as valuable (bottom 2 box 66% vs. 58% Total). Notably, assistance finding a contractor is described as valuable (top 2 box 33% vs. 24% Total) for households with income less than $40,000.

E06. There are programs to help home owners make energy efficiency improvements. I'm going to name some program features. For each one, please tell me how valuable each one might be for your household using a scale of 1 to 5, where 1 is not at all valuable and 5 is extremely valuable.

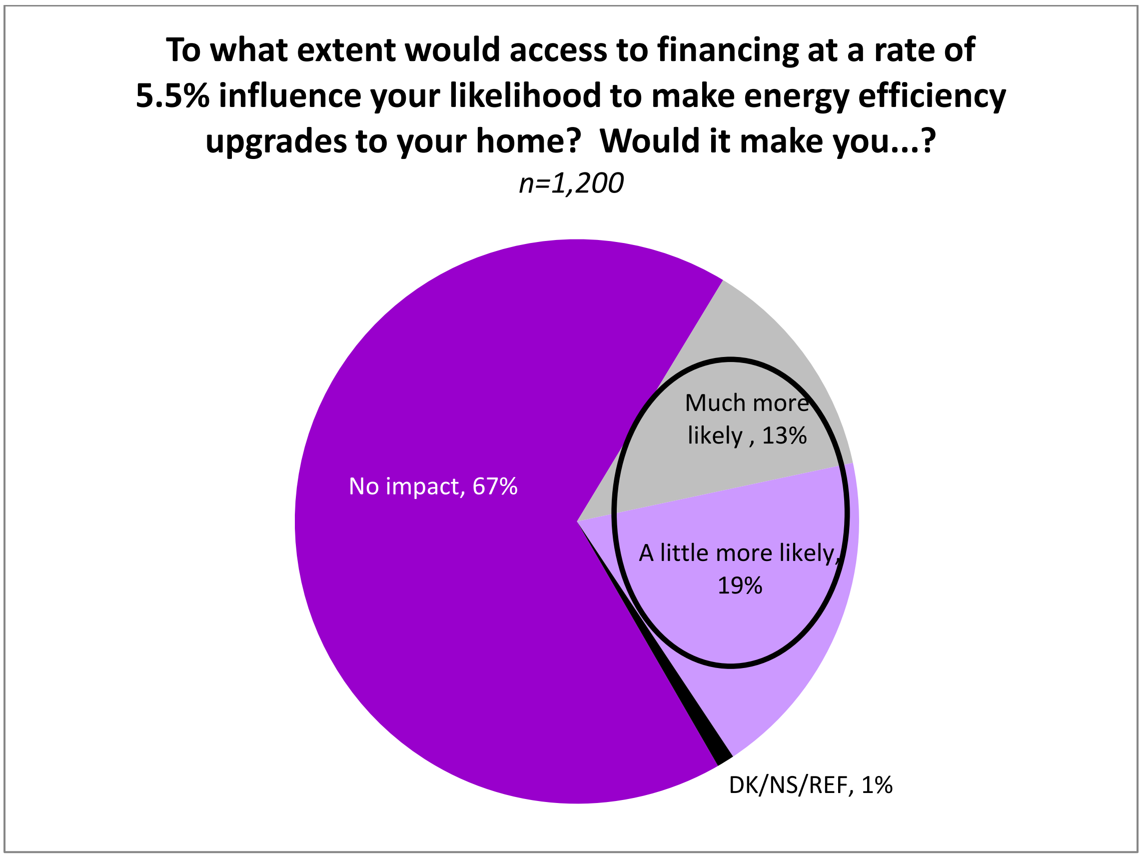


E07

Access to financing at a rate of 5.5% would have no impact on the majority (67%) of customer's likelihood to make energy efficient upgrades to their home. The share of 'no impact' increases with age, with those 65+ more apt to say that access to financing has no impact relative to their younger counter parts. Similarly those with the highest household income are more likely to say the financing offer would have no impact relative to those with lower household incomes.

Those most likely to that say that access to financing would make them either 'much' or a 'little more' likely to make energy efficient upgrades tend to be younger (<54 yrs) and to have larger households (3+ people)

Union Gas is exploring the possibility of developing a program to provide loans to help home owners finance energy efficiency improvements. Funds could be used to upgrade insulation, install new windows or a new high efficiency furnace and more, that could potentially lower a homeowners' monthly energy bill and increase the value of their home. These loans could be paid back over a period as long as 20 years. To what extent would access to financing at a rate of 5.5% influence your likelihood to make energy efficiency upgrades to your home? Would it make you...?



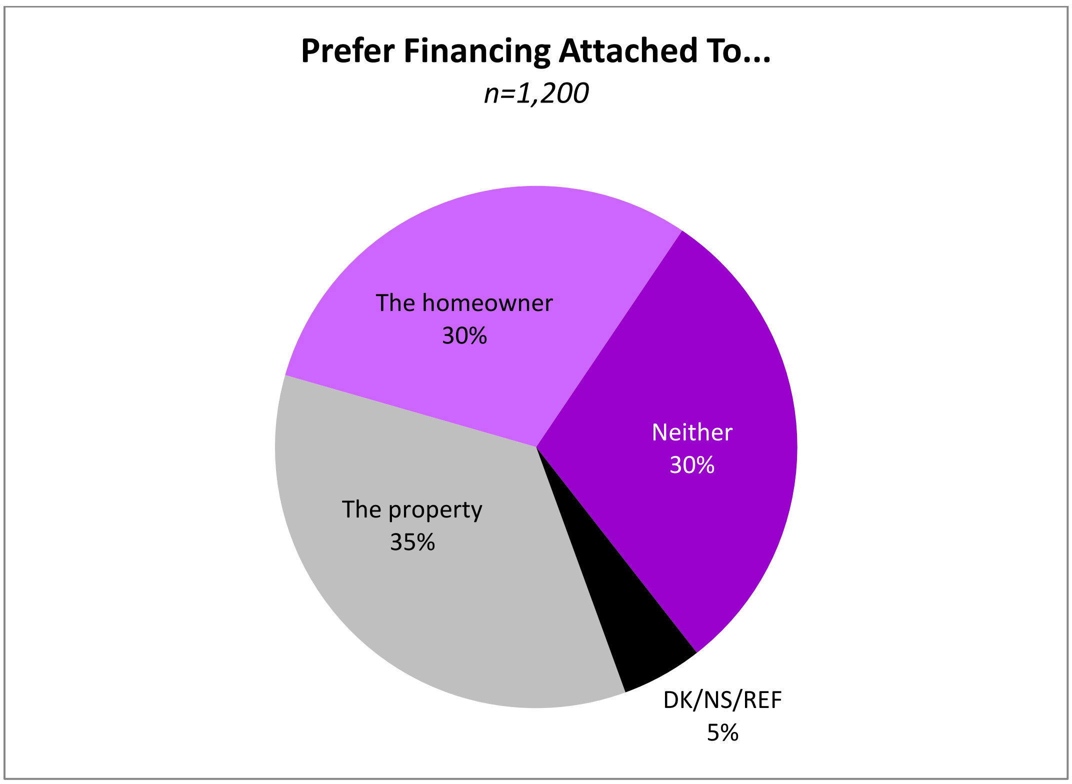
E08

Customers are evenly divided on where the loan should be attached (roughly split one-third for each attached to the property, attached to the homeowner, and neither). Younger customers (<55)are most in favour of a loan attached to property whereas older customers selected 'neither' most often.

E08. There are different ways for Union Gas to provide this financing. Of the two following scenarios, please tell me which you prefer: (Read on a rotated basis)

Scenario 1: Union Gas would attach the loan to your property and not to you the homeowner, meaning that if you decided to sell your home before the loan was paid off, the new owner would assume the payments.

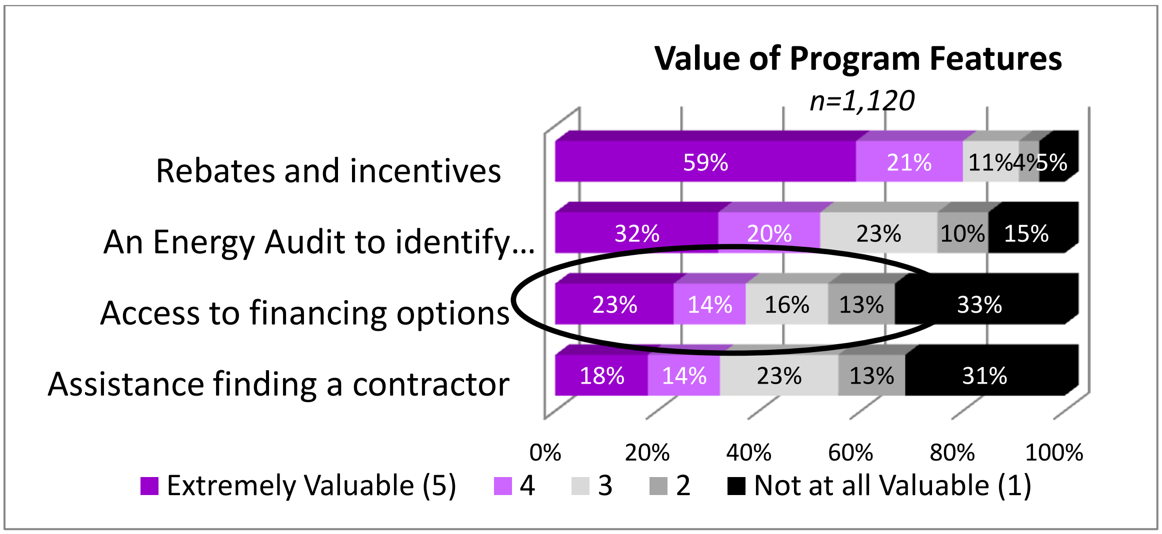
Scenario 2: Union Gas would attach the loan to the homeowner and not to the property, meaning that if you decided to sell your home before the loan was paid off, then you would still be responsible for the payments, even though you would not own the home where the energy efficiency improvements were made.



CI Mass Market Survey Results[15]

In the CI Market, 50% have made energy efficiency improvements to their business in the past year, whereas only 37% have plans to undertake any energy efficiency initiatives in the next 2 years (down from 48% who indicated plans in the 2011 study). The most often cited barrier to adopting energy efficiency measures was lack of funds (29%), capital costs (11%) and lack of time (6%). Notably, 32% indicated "nothing" or "don't know".

There are programs to help business owners make energy efficiency improvements. I'm going to list some program features. For each one please tell me on a scale of 1 to 5, where 1 is not at all valuable and 5 is extremely valuable, how valuable each one might be for your business.



As in the residential market, Rebates & Incentives are considered to be the most valuable program feature (80% valuable) followed by an Energy Audit (52%). Overall 37% indicate that access to financing options would be valuable (23% extremely valuable).

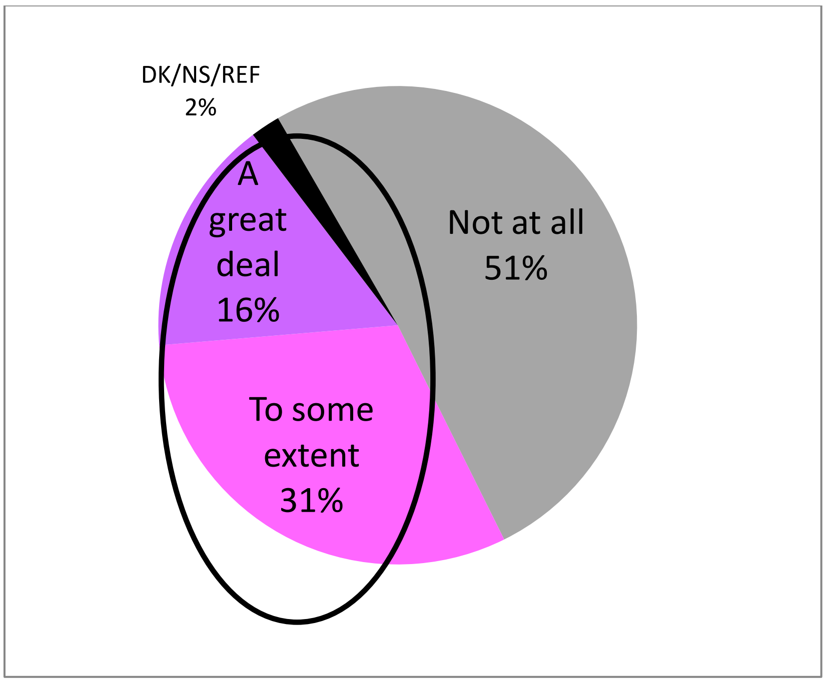
[15] Select questions were asked of CI Mass Market customers (consumption greater than 5,000 m^3 annually) as part of the Biennial Customer Satisfaction Study, which conducted telephone interviews with 1120 customers in Nov-Dec 2014 (margin of error = 2.9%).

Union Gas is exploring the possibility of developing a program to provide loans to help business owners to finance energy efficiency improvements. Funds could be used to upgrade insulation, install new windows or a new high efficiency furnace and more that could potentially lower a business' monthly energy bill. These loans could be paid back over a period as long as 20 years. To what extent would access to financing at a rate of 5.5% impact your decision to make energy efficiency upgrades to your business? Would it be…

a. Not at all because access to financing would make no difference in my decision to proceed with energy efficiency improvements.

b. To some extent because access to financing might make a difference in my decision to proceed with energy efficiency improvements

c. A great deal because access to financing would be the difference in my decision to proceed with energy efficiency improvements.



Filed: 2015-06-23
EB-2015-0029
Exhibit B.T5.Union.ED.16
Page 1 of 1

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Exhibit A, Tab 3, Appendix A, p. 20

"As noted above, it is not reasonable to offer rebates at the level of top performing jurisdictions while still achieving high participation rates within Union's budget guidelines. The experience of Ohio, Vermont and Wisconsin indicate that Union's [Home Reno Rebate] targets at the project rebate level (34% of project costs) will be challenging."

Could low-interest on-bill financing be a cost-effective option to enable Union to achieve higher Home Reno Rebate targets? When answering this question, please assume that the financing is provided by a third-party financial institution. Please fully justify your response.

Response:

No, Union does not believe that on-bill financing would be as cost effective as offering rebates, based on the following:

- Union's research results, provided at Exhibit B.T1.Union.Staff.1, show the following:
  - *Fully 66% of Union's residential customers indicated that they would expect to pay for renovations with cash or savings, with another 9% indicating they would use a personal line of credit.*
  - *Only 14% of residential customers indicated access to financing options was extremely valuable, and 49% indicate that such an offering would be "not at all valuable"*.

UNION GAS LIMITED

Answer to Interrogatory from
Environmental Defence ("ED")

Reference: Exhibit A, Tab 1, Appendix B, p. 20

Please provide an analysis of the costs and benefits of establishing a residential on-bill financing pilot project in 2016. Please assume that the financing is provided by a third-party financial institution.

Response:

Union has not performed an analysis of the costs and benefits of establishing a residential on-bill financing pilot.

Union does not believe that conducting a detailed analysis of the cost and benefits would be a prudent use of ratepayer DSM funds based on the 2014 customer research results and an environmental scan, which are both provided in the response at Exhibit B.T1.Union.Staff.1.

Please also see Exhibit B.T1.Union.Staff.1 Attachment 3.

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ANNALS OF INNOVATION

JUNE 29, 2015 ISSUE

POWER TO THE PEOPLE

Why the rise of green energy makes utility companies nervous.

BY BILL MCKIBBEN

Innovative, eco-friendly technology is now cheap enough for everyday use.

CONSTRUCTION BY STEPHEN DOYLE / PHOTOGRAPH BY ERIC HELGAS

Mark and Sara Borkowski live with their two young daughters in a century-old, fifteen-hundred-square-foot house in Rutland, Vermont. Mark drives a school bus, and Sara works as a special-ed teacher; the cost of heating and cooling their house through the year consumes a large fraction of their combined income. Last summer, however, persuaded by Green Mountain Power, the main electric utility in Vermont, the Borkowskis decided to give their home an energy makeover. In the course of several days, coördinated teams of contractors stuffed the house with new insulation, put in a heat pump for the hot water, and installed two air-source heat pumps to warm the home. They also switched all the light bulbs to L.E.D.s and put a small solar array on the slate roof of the garage.

The Borkowskis paid for the improvements, but the utility financed the charges through their electric bill, which fell the very first month. Before the makeover, from October of 2013 to January of 2014, the Borkowskis used thirty-four hundred and eleven kilowatt-hours of electricity and three hundred and twenty-five gallons of fuel oil. From October of 2014 to January of 2015, they used twenty-eight hundred and fifty-six kilowatt-hours of electricity and no oil at all. President Obama has announced that by 2025 he wants the United States to reduce its total carbon footprint by up to twenty-eight per cent of 2005 levels. The Borkowskis reduced the footprint of their house by eighty-eight per cent in a matter of days, and at no net cost.

I've travelled the world writing about and organizing against climate change, but, standing in the Borkowskis' kitchen and looking at their electric bill, I felt a fairly rare emotion: hope. The numbers reveal a sudden new truth—that innovative, energy-saving and energy-producing technology is now cheap enough for everyday use. The Borkowskis' house is not an Aspen earth shelter made of adobe and old tires, built by a former software executive who converted to planetary consciousness at Burning Man. It's an utterly plain house, with Frozen bedspreads and One Direction posters, inhabited by a working-class family of four, two rabbits, and a parakeet named Oliver. It sits in a less than picturesque neighborhood, in a town made famous in recent years for its heroin problem. Its significance lies in its ordinariness. The federal Energy Secretary, Ernest Moniz, has visited, along with the entire Vermont congressional delegation. If you can make a house like this affordably green, you should be able to do it anywhere.

Most of the technology isn't particularly exotic—these days, you can buy a solar panel or an air-source heat pump at Lowe's. But few people do, because the up-front costs are high and the options can be intimidating. If the makeover was coördinated by someone you trust, however, and financed through your electric bill, the change would be much more palatable. The energy revolution, instead of happening piecemeal, over decades, could take place fast enough to actually help an overheating planet. But all of this would require the utilities—the interface between people and power—to play a crucial role, or, at least, to get out of the way.

An electric utility is an odd beast, neither public nor exactly private. Utilities are often owned by investors, but they're almost always government-regulated, and they are charged with delivering power reliably and at an affordable price. Utilities are monopolies: since it would make no sense to have six sets of power poles and lines, utilities are granted exclusive rights to a territory. When you buy or rent a house, you automatically become the customer of the local utility, assuming that you want electricity and you don't plan to generate all of it yourself. To keep the nation's utilities honest, they are typically regulated at the state level by a public-service commission that sets rates, evaluates performance, and enforces mandates, such as a requirement that a certain amount of power come from renewable sources.

Whereas most enterprises are about risk, utilities are about safety: safe power supply, safe dividends. No surprises. As a result, the industry "has not attracted the single greatest minds," David Roberts, who has covered energy for various outlets for a decade and is now a reporter for *Vox*, told me. "If you're in a business where the customer is the public-utility commission, and after that your profits are locked in by law, it's the sleepiest business sector there is, if you could even call it a business sector. They build power plants, sit back, and the money comes in." The entire realm is protected, he added, by "a huge force field of boringness."

But what has been a virtue, by and large, is now almost certainly a vice. Scientists insist that in order to forestall global warming we need to quickly change the way we power our lives. That's perhaps most easily done by giant companies with big budgets for new technology; Google, Apple, and IKEA have all announced major plans to switch to renewable energy. For average Americans, however, the biggest source of carbon emissions is their home, so the utilities' help is crucial in making the transition. And, even without climate change, utilities face a combination of threat and opportunity from disruptive new technologies.

Consider the Borkowskis' new air-source heat pumps, which use the latent heat in the air (down to about zero degrees) to heat their home and provide hot water. These devices have made it practical for electricity to be used for tasks traditionally performed by oil and gas. Smart thermostats, such as the Nest, allow you to make your home far more energy-efficient—and can even, when connected to the "smart meters" that are now appearing on many houses, permit the utility to turn your demand down for a few seconds in response to fluctuations in the supply of sun and wind. Electric vehicles provide a major new use for electricity and, perhaps soon, the opportunity for huge numbers of idle car batteries to serve as a storage system for reserve power. (Solar and wind power can be a challenge to incorporate into the grid, because they're intermittent—cloudy days happen, the wind fails. Affordable batteries are essential to making renewable energy widely available.)

"Americans spend eight per cent of their disposable income on all forms of energy," David Crane told me. Crane is the C.E.O. of NRG, the country's biggest independent power provider; the company operates more than a hundred energy-generation facilities, selling electricity to utilities that, in turn, sell it to customers. Nobody wants that eight-per-cent figure to rise, Crane said, because when energy prices go up the country tends to trip into recession. But plenty of companies, including Crane's, would like to see a larger slice of that eight per cent. "I'm interested in electric cars, for instance, not just because of the effect on air quality but because I want to take market share away from oil," Crane said. "It's a brutal fight for market share."

Power utilities now face uncertainty of a kind that traditional phone companies faced when cellular technology emerged. A few utilities welcome the challenge; others are resisting it; and the rest are waiting for someone to tell them what to do.

The headquarters of Green Mountain Power are situated in a converted service garage on the outskirts of Burlington. On most days, Mary Powell, the company's C.E.O., can be found at one of the standing desks on the floor next to the customer-service reps. Powell, who is fifty-four, is one of the rare utility executives with an entrepreneurial background. Fresh out of college, she fell into a job at the

Reserve Fund, the world's first money-market fund, and became the associate director of operations. Eventually, she quit and moved with her fiancé to Vermont, where she worked in state government, then in banking, and then quit again, to have a daughter and work on growing the canine-apparel business that she had launched a few years earlier. "I was always terrified about my dogs during hunting season," she told me. "There was nothing to protect them. So I started making reflective protective outerwear." (You can buy it still—blaze-orange bandanna, vest, and collar for $66.85.) In 1998, Powell joined Green Mountain Power as the vice-president of human resources. The company was fighting off bankruptcy, after state regulators turned down its request for a large rate increase. Soon, as chief operating officer, Powell helped restructure Green Mountain Power, and, in 2008, she became its C.E.O.

Utilities, unlike, say, canine-apparel companies, gain their customers automatically, based on where a resident lives, and typically take little interest in them. ("You know what a customer is to a utility?" Crane asked me. "A meter.") Powell, by contrast, describes herself as "customer-obsessed." Green Mountain Power regularly surveys its customers, and the main thing Powell has learned, she said, is that Vermonters "wanted us to be as environmentally strong as possible, but they wanted us to do it without us telling them it was going to cost more money. So that became our vision: low carbon, low cost." Powell became fixated on new technologies, everything from electric-vehicle charging stations to utility-scale storage batteries. "If we move in this direction very rapidly, we can, hopefully, keep rates flat forever," she said, and, in fact, G.M.P. cut its electric rates by two per cent last year. She started searching for partners; at least three contractors worked on the Borkowskis' house, and "that collaboration was one of the real innovations. Not approaching customers in a siloed way, with a dozen companies each pitching a piece. It's 'How can we come to you with a package?'"

How all this will translate into revenue isn't entirely clear, not to Green Mountain or to anyone else in the business. But the cash flow available to the utilities gives them plenty of low-cost capital to work with. They can make money by leasing heat pumps and solar panels to customers. The insulators and other contractors will contribute something, because working with Green Mountain reduces the cost of acquiring new customers. And there's money to be saved. Currently, utilities plan their operations around the busiest day of the year, making sure they have the capacity to meet peak demand on the hottest August afternoon. But as Green Mountain Power modernizes one home after another—so far it's enabled a few dozen fully remodelled "E-homes" and more than a hundred partial makeovers—the utility gains the potential ability to briefly turn down water heaters and air-conditioners during high-usage periods. This "demand management" allows the utility to avoid peak charges from the regional power grid and can save it hundreds of dollars per customer each year.

"You wouldn't notice, because we're turning down the water heater for just a few seconds," Powell said. But getting permission to do that, or even getting customers to believe that you can save them money with a makeover, "requires a different kind of relationship. Can we really build a deep emotional and intellectual relationship with our customers?"

There are no guarantees, Powell said. But so far she has met every revenue goal set by Green Mountain Power's corporate parent, the Canadian company Gaz Métro. "A challenge in the utility culture is precisely that it's built on guarantees. Innovation happens when there are no guarantees."

Arguably, the era's most disruptive technology is the solar panel. Its price has dropped ninety-nine per cent in the past four decades, and roughly seventy-five per cent in the past six years; it now produces power nearly as cheaply as coal or gas, a condition that energy experts refer to as "grid parity." And because it's a technology, rather than a fuel, the price should continue to fall, as it has for cell phones. Solar power is being adopted most rapidly in places where there is no grid—it's cheaper and quicker to stick panels on the roofs of huts in villages than to build a centralized power station and run poles and wires. In Bangladesh, crews install sixty thousand solar arrays a month. Even in the U.S., where almost everyone has been connected to the grid for decades, solar prices have fallen to the point where, with the help of a federal tax credit, an enterprising company can make money installing solar panels.

One morning in March, I stood on the roof of a suburban ranch in Surprise, a suburb of Phoenix, with Lyndon Rive, the co-founder and C.E.O. of Solar City, the biggest and the fastest-growing installer of rooftop solar in the country. Around us, a five-man crew was laying out a grid of solar panels, following a plan designed by an employee in California who had looked up the roof on Google Earth and measured it. The crew had assembled at the house at seven that morning, and by 5 P.M. the new solar array would be ready to be turned on. The homeowner, like the Borkowskis, was paying nothing up front, and within the first month would see her total electric bill decline. Glancing around the neighborhood, I counted fourteen solar arrays on a hundred or so houses. "It's like e-mail in 1991," Rive said. "When I look out at this street, there's no reason every one of these houses can't have solar in ten years."

Rive is the cousin of the Tesla pioneer Elon Musk, who is the chairman of Solar City's board of directors. Currently, Rive said, the company finishes a solar array somewhere in its eighteen-state service area every three minutes. "That sounds impressive, but it's only two hundred thousand homes so far, out of forty million. My goal is to get it to one home every three seconds. Or maybe we could go faster than that—one every second," he said, snapping his fingers. He pulled an iPhone out of his pocket, called up the calculator app, and punched in some numbers. “At that rate, we could do every house in . . . seventy-six years. No, that’s too long—I forgot a division. In a year and a half.”

That pace would change the projections for climate change, but it would also require a major government initiative, akin to the one that revitalized industry at the start of the Second World War. Even without it, Solar City has grown by a hundred per cent each year for the past seven years, in part by lowering the soft costs of installation. A job that once took three days can now be done in one, and Rive showed me a training video of a California crew that could do two houses in a day and still have time to surf. By next year, solar will be the fastest-growing new source of energy in the country, approaching half of new capacity. That’s still only a fraction of the total capacity, Rive said, “but if you just maintain that, just plot out the line with the retirement of old plants, it’s inevitable that it will be over fifty per cent of the total generating capacity eventually. And that’s assuming nothing changes.” In fact, he noted, each month brings some new improvement in panels or batteries.

But many utilities see residential solar power as an existential threat. In 2013, an industry trade group called the Edison Electric Institute warned that utilities face what company executives were quick to call “a death spiral.” As customers began to generate more of their own electricity from the solar panels on their roofs, utility revenues would begin to decline, and the remaining customers would have to pay more for the poles and wires that keep the grid alive. That would increase the incentive for the remaining customers to leave.

Since the death-spiral session, utilities around the country have sought to slow the growth of solar: by supporting laws and regulations that would reduce targets for renewable energy; by ending “net metering” laws that force utilities to pay solar customers retail prices for the surplus energy they put back on the grid; by imposing “connection fees” to make up for lost revenues. Much of the campaigning has been spurred by the right-wing American Legislative Exchange Council and funded by various groups linked to the Koch brothers and their fossil-fuel fortune. In 2008, when Solar City first expanded into Arizona, the state had just announced a target for renewable energy, and the utilities were offering generous rebates to customers who installed solar panels. At first, few homeowners took advantage of the offer—the up-front cost, which ran to twenty thousand dollars or more, was too high. It took the efforts of Solar City, and other competitors using the same no-cost leasing plan, to ignite the market.

“The utilities were always convinced that they could throttle down solar just by tuning down the rebate they were offering,” Rive said. “What caught them off guard was when costs came down to the point where we didn’t need their rebate for solar to make sense. Suddenly, they couldn't control the outcome anymore. And suddenly you didn't see any more solar billboards, and suddenly they started taking a hostile approach."

Arizona's biggest utility, Arizona Public Service, insists that it is "pro-solar" and notes that it has built its own utility-owned solar arrays in the desert. But it views customers who install rooftop panels as, in essence, cheaters: they get the benefits of the grid—uninterrupted power, even on cloudy days—but, because they provide so much of their own electricity, they aren't paying their fair share of the total price. In 2013, A.P.S. asked state regulators for permission to charge anyone who wanted to put up a solar panel a fee. "Whether or not you're producing enough electricity to power your house, you're still connected to the grid," Jeff Guldner, the company's senior vice-president for public policy, said. "These costs get recovered from somebody, and that somebody is customers who don't have solar."

The argument makes a certain intuitive sense, even if utilities like Green Mountain Power, and a fair amount of academic research, suggest that solar customers save utilities as much money as they cost them, by shaving peak demand and by moving power generation closer to clients, which reduces the electricity lost on power lines. The Arizona Corporation Commission agreed with A.P.S. and allowed the utility to charge an average of about five dollars a month, a tenth of the fifty-dollar fee it had requested. Solar City decided not to appeal the ruling. The savings the company was offering many customers still exceeded the new charge, and business continued to grow.

But A.P.S. went on the offensive. In the fall of 2014, as members of the Arizona Corporation Commission, which regulates many of the state's utilities, began running for election, the company contributed to the campaigns of sympathetic candidates, although it declined to say whom it has supported. (The utility has said only that it "periodically contributes to candidates, causes and organizations that support economic growth, sound energy policy, and other issues important to our company and our customers.") A.P.S. is even widely suspected of helping to fund the campaign of a candidate for Arizona Secretary of State, because his father was a key vote on the Corporation Commission.

I listened to stories like this for the better part of an afternoon, sitting in a Scottsdale law office with Court Rich and Jason Rose, two self-described "strongly conservative" political operatives who had gone to work for a coalition of companies, including Solar City, to help elect solar advocates to the Corporation Commission's board of directors. They were mercenary, but they also seemed genuinely outraged. "A.P.S. is a quasi-governmental agency, and they're using ratepayer money to influence elections?" Rich said. "All of a sudden, we started seeing anti-solar commercials all over the TV. I mean, the ads were comparing solar customers to people stealing from children." (A.P.S. says that its political contributions were paid for by employee contributions, not by ratepayer revenue.)

The solar advocates didn't prevail in the election. "In politics, there's a direct correlation between spend and win," Rose said. "And our side was outspent considerably." But the utilities' argument for self-preservation may have reached its limit. Rich and Rose ran a campaign that leaned heavily on standard conservative tropes of self-reliance and freedom.

"Solar should be our issue," Rose said. "Obamacare is bad because it diminishes health-care choice. Public education is bad because it diminishes school choice. You'd think it would apply as well to energy." They helped form a group called Tell Utilities Solar Won't Be Killed, or TUSK—"from the Republican-elephant thing," Rose said. "We have a lot of Tusk and Trunk dinners in the G.O.P." For its chair, they recruited Barry Goldwater, Jr., the son of the original Arizona Republican idol.

Indeed, an odd coalition of environmentalists and conservatives has sprung up around the country to defend solar power. In Georgia, a Tea Party activist named Debbie Dooley and the Sierra Club fought successfully to allow the leasing of rooftop solar panels in the state. Their joint project, the Green Tea Coalition, has spread to Florida, which has some of the nation's most restrictive solar laws. They are working to collect seven hundred thousand signatures by next February, enough to put a measure on the ballot that would amend the state's constitution to allow residents with solar panels to sell electricity back to the grid, as is done in many other states.

But in December Arizona's second-largest utility, the Salt River Project, imposed charges of some fifty dollars a month on the average new solar installation. S.R.P. also insists that it is "pro-solar," but the new charges effectively make it economically difficult for homeowners in the company's service district—in the sunniest state in the country, and in a city that roots for the Phoenix Suns—to install solar panels. Rooftop installations, booming six months ago, have all but halted, and Solar City is transferring large numbers of workers to other districts, as well as suing the utility to have the new charges overturned. Citing the lawsuit, S.R.P. refused requests for an interview, issuing a statement that says, in part, "S.R.P. is confident that its new price plan will be determined to be appropriate and is confident that it will prevail in all such challenges to it."

Most utilities are neither as innovative as Vermont's nor as scared as Arizona's; most are simply waiting for guidance.

“There are no thirty-year-old C.E.O.s of electric utilities, no Zuckerbergs,” David Crane, the NRG chief, told me. “You have to pay your dues, come up through the ranks. You become C.E.O. when you have five years, max, left. Some of them are just not worrying about ten, fifteen years in the future.” A member of the executive committee at a major mid-Atlantic utility said, “We don’t want to be Kodak, because we can see digital imaging on the horizon. But the regulators are damned slow in figuring out which way we should move. There are eleven hundred utilities in this country, and they’re regulated at the state level, so change is going to be very dispersed.”

On one of the first hot days of May, I joined Richard Kauffman, the chairman of energy and finance for New York State, and the state’s “energy czar,” as he and several aides piled into a stuffy L train at Fourteenth Street. In 2013, a few months after Hurricane Sandy left many New Yorkers powerless for days, Governor Andrew Cuomo accused utilities of being “the equivalent of vinyl records in the age of the iPod” and appointed Kauffman to prod them into action. Kauffman soon announced a program of incentives that would eventually be called REV—Reforming the Energy Vision. Around the country, other regulators are watching to see how the initiative fares.

Forty-five minutes after boarding the subway, we got off at East 105th Street, in the heart of warehouse Brooklyn, on the edge of Canarsie. We walked half a mile to look at a particular warehouse belonging to a fish wholesaler. Con Ed, faced with growing electrical demand in the borough, had planned to build a billion-dollar substation on the site. But, in the first real test of the REV plan, the utility will instead supply some of the additional power by encouraging customers to install solar panels and cutting-edge storage batteries. It will also pay customers to limit their usage during peak hours, thereby reducing over-all demand. The effort will cost Con Ed many millions of dollars less than building a new substation, which would seem to make the decision an obvious one.

But, in the odd world of regulated utilities, a company like Con Ed traditionally makes money by building more stuff: put in a billion-dollar substation and you can “rate base” it, making customers pay the cost, plus a ten-per-cent markup, for decades. That arrangement worked well when society needed utilities to build the electrical system, to serve everyone, and when the cheapest technical solution involved big plants “pushing electrons in one direction,” Kauffman said. But today “the system is not just energy-inefficient; it’s capital-inefficient.” At any given moment, New York’s utilities are using only about fifty-five per cent of their system capacity. “No other industry uses capital like that anymore,” Kauffman said. The regulations are perverse:

new software that can reduce electrical demand must be expensed in the current year, while a new wooden pole can generate that ten-per-cent markup for the utility in the course of its fifty-year life span. A pole makes money—hence, poles.

In the next decade, if New York's power industry stumbles along on its current course it will spend about thirty billion dollars on more substations, and on other similarly outdated technology. Electricity costs will continue to rise, and New York's are already among the highest in the country. "That would lead more people to defect from the grid," Kauffman said. "Maybe it's not the death spiral, but it becomes a zombie industry. And, as rates go up, employers would say it's too costly to do business in New York and they'd leave."

Through REV, Kauffman is trying to change the rules so that the utilities can both shift direction and make money. Persuading Con Ed to forgo the substation meant figuring out how to pay them "performance incentives" to instead install the cheaper solar power and storage batteries. In the months to come, New Yorkers should begin to see other examples. "Maybe some appliance company will say to a consumer, 'We'll give you all new appliances for free, and you'll have the same electric bill less five per cent,'" Kauffman said. Your fridge would come with a chip that allowed it to be cycled off for a moment when demand was peaking, and, as the middleman in the transaction, the utility could take a cut. "The same thing with home entertainment—each new generation of flat-screen TVs uses a lot less power."

Kauffman has all sorts of plans, from a "green bank"—to attract private-sector capital to finance extensive energy-saving retrofits—to new rules that would pressure utilities to play nicely with outside partners like Solar City. "It's kind of a Hannah Arendt thing," he said. "There's not a lot of intentional evil in utilities. But we've created a golden cage for them, protected them from enormous trends." We were on the subway again, and as it clattered back toward Manhattan Kauffman had to shout to be heard: "Our aim is to create a policy environment that is not standing against the forces of history but is in line with them."

Technological change will fundamentally transform the power industry. The question is whether that transformation can happen fast enough to matter, either for the survival of the utilities or, more important, for the preservation of the climate. In the past, energy transformations—wood to coal, coal to oil—have taken fifty years or more to unfold as infrastructure was slowly replaced. New York has a home-energy-audit program, whereby a team will come to your home, determine how much insulation it needs, and identify other ways of boosting your energy efficiency, much the way that Green Mountain Power assessed the Borkowskis' house. "But at current rates of penetration it will take us centuries to do the whole state," Kauffman said.

This time, though, technological change may be coming so rapidly that a quick adaptation is possible. The week that I was in Canarsie with Kauffman, Mary Powell flew to California to attend Elon Musk's announcement of his new home battery, the Powerwall. Green Mountain Power was the only utility in the country that was ready to sell the new battery on the first day that it became available. And Powell was excited by its low price: three thousand dollars, far below what analysts had predicted, and low enough that her company could immediately begin installing it for customers, especially those who wanted backup electricity in case a snowstorm disabled the grid.

A week after the battery launch, Musk described demand for the batteries as "just nutty" and "off the hook." His company had already sold all the batteries it could make through the middle of next year and was discussing expanding its giant new factory, in Nevada, even before construction was completed. The day after Tesla's launch, Solar City announced that, beginning in 2016, it will routinely package Musk's new batteries with its panels in some markets. If utilities won't relent and embrace innovation, homes and businesses will soon be able to circumvent them altogether. The threat is real enough that it might actually soften the attitude of even recalcitrant utility executives.

Meanwhile, Green Mountain Power is almost ready to flip the switch at its biggest solar farm, built on top of Rutland's old dump. In July, when the site flickers on, the city will be the most solarized in northern New England. But the less obvious changes count even more. Dave and Karen Correll live across town from the Borkowskis, in a well-kept Colonial Cape that was another of the original batch of "E-home" renovations. First, contractors re-insulated the basement and the attic. Then came the air-source heat pump, which the Corrells lease from Green Mountain Power for forty-seven dollars a month. Their oil bill fell sixty-seven per cent during the course of Vermont's long, cold winter of 2015. "I can't wait to see what comes out next," Karen told me. "Our furnace is about at the end of its life, and I can't wait to replace it."

Neither the Corrells nor the Borkowskis changed their homes out of concern for global warming. ("If it's not on the Disney Channel, I don't hear about it," Sara Borkowski said.) But that's the point: a bold reworking of energy systems, long necessary and expensive, is now necessary and much more affordable. That could make for a very different world. ♦

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