ONTARIO ENERGY BOARD

EB-2014-0134

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

AND IN THE MATTER OF the consultation process for developing a new demand side management framework for natural gas distributors.

COMPENDIUM OF MATERIALS REFERRED TO IN THE SUBMISSIONS OF ENVIRONMENTAL DEFENCE

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The Economic Impacts of Reducing Natural Gas Use in Ontario

Prepared for
Ontario Clean Air Alliance
and
Ontario Clean Air Alliance Research Inc.

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The EJLB Foundation, The Toronto Atmospheric Fund and
The Taylor Irwin Family Fund at the Toronto Community Foundation

April 2011

INTRODUCTION

The Ontario Clean Air Alliance and the Ontario Clean Air Alliance Research Inc. requested the Centre for Spatial Economics (C_4SE) to undertake a study that looks at the economic impacts of reducing the use of natural gas in Ontario. The possibility of achieving a significant reduction in the use of natural gas has been shown in a study undertaken for Enbridge Gas Distribution that estimated possible reductions in natural gas use on the part of its customers. The current study examines the economic impacts of reducing natural gas in the province by creating a projection for the future economic performance of the Ontario economy that contains a reduction in the use of natural gas that is similar in nature to that shown in the Enbridge Gas Distribution analysis and compares the results of this scenario against a projection that does not contain this reduction.

The next section provides a description of the approach adopted to estimate the impacts of reducing the use of natural gas and the assumptions behind the approach. The third section discusses the expected impacts of reducing the use of natural gas on the economy from a qualitative point of view. The fourth section then presents the quantitative estimates of the impacts found using the assumptions for the reduction in natural gas considered.

STUDY APPROACH AND ASSUMPTIONS

Enbridge Gas Distribution commissioned a study regarding the possibility of reducing the use of natural gas by its customers in Ontario using a Demand Side Management (DSM) approach (Marbek Resource Consultants Ltd. "Natural Gas Energy Efficiency Potential: Update 2008, Residential, Commercial and Industrial Sectors Synthesis Report," September 2009). The results of the study suggest estimates of possible reductions in natural gas use for industrial, commercial, and residential customers under different assumptions regarding DSM costs. Under its Economic Potential Forecast, for example, reductions in residential, commercial, and industrial, natural gas usage over a 10-year period are estimated at 18, 29, and 34 percent, respectively. These reductions are to be realized (Marbek, op. cit. page 4):

> ".. if all equipment and building envelopes were upgraded to the level that is cost-effective from Enbridge's perspective. All the energy efficiency technologies and measures that have a positive measure TRC.. (net benefits that result from an investment in an efficiency technology or measure).. are incorporated into the Economic Potential Forecast. These technologies and measures are applied at either natural stock turnover rates or at designated years for immediate application."

The Ontario Clean Air Alliance is interested in estimating the impact on the Ontario economy if a reduction in natural gas use could be achieved in the province as a whole. The assumptions adopted for the reduction in natural gas use found in the Enbridge study serve as a starting point for those used in this study. The reduction is assumed to take place over the 10-year time period 2012 to 2021.

The approach adopted to estimate the economic impacts on Ontario of reducing the use of natural gas employs the C_4SE macroeconomic model of the Ontario economy. This model is used to prepare two economic projections for the future performance of the economy. The first projection shows the performance of the economy without the reduction in the use of natural gas. The second one shows the performance when the usage of natural gas is reduced. The impacts on the economy are then estimated by comparing the results of the two projections for key economic and fiscal variables such real Gross Domestic Product (GDP), the Consumer Price Index (CPI), employment, population, and government budget balances.

The C_4SE macroeconomic model is a multi-sector (industry) model that assumes the existence of a gross output (total value of production) KLEM production technology for the different sectors – KLEM stands for the production inputs of capital, labour, energy, and materials. It incorporates variable input-output coefficients that respond to changes in relative prices for production inputs. For example, increases in the price of natural gas will lead to a reduction in natural gas's share of total inputs to gross output and an increase in the share for the other inputs. The model also incorporates a Green House Gas emissions component that estimates CO_2 equivalent emissions by industry.

The projection that does not contain the reductions in natural gas is called the base case projection. It is created by making assumptions about the key drivers for the Ontario economy such as economic growth and inflation in Ontario's major trading partners, oil prices, natural gas prices, fiscal policy, and so on. The projection with the reductions in natural gas is created using the base case assumptions and then reducing the input shares of natural gas for the various industries along with the consumer expenditure share of natural gas for households. The input shares are variables in the macroeconomic model.

The Enbridge study does not cover all of Ontario's economy. The current study wishes to expand the coverage to the province as whole. The reductions in natural gas use employed are 25 percent for the industrial sector, 20 percent for the commercial sector, and 15 percent for the residential sector. These reductions are lower and, therefore, more conservative than those found in the Enbridge Economic Potential Forecast.

It is assumed that an increase in the share of capital in gross output will occur with the reduction in natural gas use in gross output as firms purchase new energy efficient technologies. As a result, there will be an increase in the share of value-added (net output or GDP) in gross output in the economy. In the case of households, the reduction in the share of natural gas in consumer expenditures is replaced by an increase in the share of the other consumer expenditure categories.

While the Enbridge study provides estimates of reductions in natural gas use, it does not contain estimates of the amount of capital expenditures that would be required to achieve these reductions. The C_4SE model suggests that the "incremental" increase in the stock of capital over the projection period required to achieve the non-residential natural gas reductions measured in $2010 would be about $4 billion. For the residential sector it is assumed that a $3 billion increase in the value of residential structures would be required – which is about $500 per household (occupied housing unit). This assumption is a "rough" estimate, but is similar to the ratio of the increases in non-residential capital stock to natural gas reductions produced by the model. Lower amounts of residential expenditures would reduce the economic impact on the economy and higher ones would increase the impact.

It is also assumed that the prices for capital goods purchased to reduce natural gas usage will not rise from those found in the base case projection other than through possible increases in wholesale and retail trade margins for local firms as demand pressures rise. The prices for imported capital goods remain unchanged from base case values.

While the reductions in natural gas use are assumed to take place over the 10-year period 2012 to 2021, the projection period is extended for another 5 years to 2026. The longer time period is adopted to allow the economy to fully adjust to both the direct and indirect impacts of the reductions in the use of natural gas on the economy.

A final set of assumptions includes the absence of a response of fiscal and monetary policy on the part of governments. The Bank of Canada will not respond to changes in inflation associated with the reduction in natural gas use. Governments will not change policies in the face of changes in their budget balances. Any improvements or deterioration in budget balances will lead to changes in government debt.

EXPECTED IMPACTS

Before presenting the quantitative estimates of the impact of the reduction in natural gas use it is worthwhile to review the nature of impacts expected from a qualitative point of view – that is, directions of change rather than the estimated size of change.

The reduction in the use of natural gas is to be accomplished by replacing natural gas with more energy efficient capital equipment. This replacement is expected to allow firms to produce the same amount of goods and services they did when using natural gas because the more productive capital replaces the contribution of natural gas use in gross output. It should be noted that the reductions in natural gas use implemented through the model's input shares will not likely reduce natural gas use in the same proportion. This difference is a result of changes in economic performance caused by the changes in technology. While the share of natural gas in the economy is reduced, the actual size of the economy will increase, which in turn, will lead to additional use of natural gas. Nevertheless, the latter increase will be small in relation to the decline that results from introducing more efficient capital equipment.

Significant increases in investment expenditures in the economy are expected to be observed over the period relative to the base case projection when firms substitute capital for natural gas. Over the long run when the more efficient capital begins to wear out, additional replacement expenditures are expected with the higher valued capital in contrast to the relatively lower replacement values for the old capital.

The purchase of new equipment and the construction of structures needed to achieve lower gas use will increase production and employment in industries throughout the economy. The increased employment and disposable income will lead to increases in consumer and housing expenditures. These increases, in turn, will lead to additional production and employment, and so on.

Because Ontario does not produce natural gas the reduction in its use will not have a major negative impact on the economy. Nevertheless, firms in the natural gas distribution system are likely to see a reduction in their sales, which will offset somewhat the increases in GDP resulting from the more productive capital.

The fall in natural gas use will be observed through a reduction in provincial imports, which will lead to an improvement in the trade balance (exports minus imports) over the long run. During the period in which the capital is being replaced, nevertheless, the reduction in natural gas imports will be offset by imports of machinery and equipment. The import share of the machinery that will be purchased to reduce natural gas use is high for the province.

The higher GDP associated with the increase in capital to replace natural gas will lead to increases in labour productivity, which, in turn, will result in increases in wages and personal income. The latter will cause an increase in consumer expenditures, in addition to that observed as a result of the increased investment activity mentioned above.

The increased economic activity resulting from the reduction in gas use will also result in an improvement in the budget balances of the federal and provincial governments. This improvement comes from increases in revenues from both income taxes – personal and corporate – and indirect taxes such as the HST. Expenditures also rise as the increase in employment results in additional persons moving into the province, but this increase will be lower than the increase in revenues.

The reduction in the use of natural gas will lead to a reduction in CO_2 emissions. This reduction will be somewhat offset by increases in emissions resulting from a higher level of economic activity associated with replacing the natural gas with more energy efficient capital.

ESTIMATED IMPACTS

Estimates of the impacts of reducing natural gas use in the province for key economic indicators are shown in **Table 1**. The impacts for many indicators refer to the percentage differences and level differences from the base case projection values. The level differences for expenditure or income variables are measured in millions of 2010 dollars.

The results for real GDP show a 0.6 percentage point increase from the base case in 2026. This increase represents $5.1 billion measured in 2010 dollars. It should be noted that part of the

TABLE 1: IMPACT ON KEY ECONOMIC INDICATORS
(Level or Percentage Difference from Base Case)

	2016	2021	2026
Real GDP $2010 Millions			
% Difference	0.2	0.7	0.6
Difference	1706	5497	5144
GDP Deflator % Difference	0	0.1	0
Consumer Expenditures $2010 Millions			
% Difference	0.2	0.6	0.5
Difference	787	2694	2630
Residential Investment $2010 Millions			
% Difference	1.4	3	0.6
Difference	686	1651	394
Non-Residential Investment $2010 Millions			
% Difference	0.5	1.3	0.7
Difference	346	891	559
Exports $2010 Millions			
% Difference	0	-0.1	0
Difference	-49	-284	142
Imports $2010 Millions			
% Difference	0.1	0	-0.1
Difference	204	126	-628
CPI % Difference	0	0.1	0
Hourly Wage Rate $ % Difference	0.2	0.5	0.2
Employment 000s			
% Difference	0.2	0.4	0.4
Difference	12.2	33.8	28.5
Productivity (GDP/Hour) % Difference	0	0.2	0.2
Personal Income $2010 Millions			
% Difference	0.3	0.7	0.5
Difference	1215	3738	2612
Corporate Profits Before Tax $2010 Millions			
% Difference	0.1	0.7	0.6
Difference	73	446	451
Federal Net Lending $2010 Millions Difference	231	496	148
Provincial Net Lending $2010 Millions Difference	159	479	443
Natural Gas Final Demand (BCF)			
Difference	-69	-196	-192
% Difference	-6.9	-16.1	-15.4
Total Provincial CO2 Equivalent Emissions (KT)			
Difference	-4107	-13742	-13061
% Difference	-2.1	-6.1	-5.5

increase in GDP and some of its components is a result of an increase in population caused by higher employment leading to additional migration to the province.

Consumer expenditures account for the largest amount of the increase in GDP in 2026 where the percentage difference in expenditures is 0.5. The increase in consumer expenditures is the result of an increase in personal income, which rises 0.5 percent.

The increase in personal income results from increases in employment and wages. The wage rate rises 0.2 percent above base case values while there is a 0.4 percent increase in employment. The increase in employment in level terms is 29 thousand in 2026. Part of the increase in wages is due to the higher productivity that results from the increase in capital with the reduction in the use of natural gas. The fact that the Consumer Price Index (CPI) does not change over the period adds to the purchasing power of the wage increase.

As expected non-residential investment expenditures show a noticeable increase reaching 0.7 percent above base case values in 2026. The latter increase is less than the 1.3 percent observed for 2021 when the use of natural gas is being reduced through investments in energy saving capital.

There is also a 3.0 increase in residential investment to 2021, which falls to 0.6 percent in 2026 as the additional residential capital needed to reduce natural gas consumption is put in place. Some of the higher residential investment is accounted for by an increase in population associated with the higher employment attracting more people to the province.

Imports rise to 2021 in the projection where natural gas use is reduced, which is a result of both higher investment and consumer expenditures. Nevertheless, they fall later as the higher level of investment and associated activity is reduced. The increase in productivity that is caused by the reduction in the use of natural gas reduces business costs enough to cause exports to rise slightly by 2026. This latter increase leads to an improvement in the trade balance of almost $800 million that year. The reduced costs are also responsible for the increase in corporate profits before taxes over the projection period.

The federal and provincial governments see an improvement in their budget balances with the increased economic activity. The federal budget balance by 2026 is nearly $150 million higher while that for the provincial government is about $445 million higher. The sum of these differences over the period suggests about a $3.8 and $4.4 billion decline in federal and provincial government debt, respectively.

The percentage reduction in natural gas use for total final demand – which excludes natural gas used to produce electricity – is 15.4 percent in 2026. The reduction in physical units is 192 billion cubic feet of natural gas (BCF). This reduction divided into the increase in GDP in 2026 shows a $26 million dollar increase in GDP for each 1 BCF of natural gas reduction.

The reduction in the use of natural gas has a noticeable impact on total provincial CO_2 emissions over the projection period. By 2026 the level of CO_2 equivalent emissions is reduced 5.5 percent or 13.1 megatonnes with the replacement of natural gas by the more energy efficient capital.

The estimated percentage impacts on the industries in the economy that are covered in the C_4SE model are shown in **Table 2**. The impacts on the various industries reflect their relative intensities of natural gas use as well as their involvement in producing and installing capital goods. The construction industry, for example, will see a larger increase in activity as it builds and installs new capital. Industries with high shares of their production represented by natural gas such as primary metals will tend to have larger responses to the reduction in gas use.

The mining and manufacturing industries see relatively large increases in GDP because they use relatively large amounts of natural gas. Within the manufacturing industry the two automobile related industries show the smallest increase while primary metals and other manufacturing, which includes the pulp and paper industry, show relatively large increases in GDP.

As expected the construction industry registers a large increase to 2021 with a 2.0 percent difference between the base case projection and the reduced natural gas projection. This impact declines to 0.7 percent once the conversion to more efficient capital is completed.

The impacts on the service industries reflect in part the higher population associated with the employment increase as well as a reduction in natural gas use. The retail and wholesale trade, finance, insurance, and real estate, and accommodation and food services show the largest increases among private services.

TABLE 2: IMPACT ON INDUSTRY GDP (%)
(Percentage Difference from Base Case)

	2016	2021	2026
Total	0.2	0.7	0.6
Agriculture	0.1	0.2	0.2
Forestry	0.2	0.4	0.4
Mining	0.4	1.3	1.3
Manufacturing	0.4	1.3	1.1
Plastics	0.2	0.6	0.5
Motor Vehicle Assembly	0.1	0.4	0.3
Motor Vehicle Parts	0.1	0.4	0.4
Machinery	0.3	0.7	0.7
Fabricated Metals	0.3	0.8	0.6
Primary Metals	0.7	2.1	1.9
Other Manufacturing	0.6	1.8	1.6
Construction	0.8	2	0.7
Utilities	0.1	0.5	0.4
Transportation & Warehousing	0.1	0.3	0.3
Trade	0.2	0.6	0.5
Finance, Insurance & Real Estate	0.2	0.7	0.6
Professional, Scientific & Management Services	0.1	0.3	0.2
Accommodation & Food	0.2	0.6	0.5
Health Services	0.1	0.4	0.4
Other Services	0.2	0.6	0.5
Education Services	0.2	0.7	0.6
Government Services	0.1	0.4	0.5

APPENDIX: THE CENTRE FOR SPATIAL ECONOMICS

The Centre for Spatial Economics (C_4SE) monitors and forecasts economic and demographic change throughout Canada at virtually all levels of geography. The C_4SE also prepares customized studies on the economic, industrial and community impacts of various fiscal and other policy changes, and develops customized impact and projection models for in-house client use. Our clients include government departments, crown corporations, manufacturers, retailers and real estate developers.

The C_4SE was formed in July 2000 through an initiative of two consulting firms: Strategic Projections Inc. and Stokes Economic Consulting Incorporated. These two firms specialize in demographic and economic research. A key part of this research has been the geographical distribution of demographic and economic activity. The C_4SE was established as a partnership of SPI and SEC to improve the quality of information and research conducted in Canada and to make the information and research available to organizations requiring such information, and to the public as the opportunity arises. The C_4SE draws from a list of academics and research consultants on an as needed basis to minimize overhead costs and to obtain the best researchers for the topic at hand.

The staff of the C_4SE is currently as follows:
Ernie Stokes - Managing Partner
Tom McCormack - Partner
Robert Fairholm - Partner
Robin Somerville - Partner
Aaron Stokes - Staff Economist
Tara Schill - Staff Economist
Adam Papp – Staff Economist
Robert Daniells - Consultant
Sam Patayanikorn – Consultant

Ernie Stokes, the author of this report, is the Managing Partner of the C_4SE, as well as the President of Stokes Economic Consulting. He has more than 30 years experience as an economic advisor in both the private and public sectors. Ernie has worked both in North America and developing countries. He has a Ph. D. in economics from Queen's University (1979). Prior to establishing Stokes Economic Consulting in 1995 he served as Managing Director, the WEFA Group, Canada (1989 to 1994), as senior economist with the Alberta Energy Company (1987 to 1989), as a senior official with the Canada Department of Finance (1985 to 1987) and as Director of the National Forecasting Group with the Conference Board (1978 to 1984).

Stokes is currently a member of the B.C. Minister of Finance Forecast Council and the Ontario Minister of Finance Forecast Council as well as an expert on the Ontario Minister of Infrastructure Strategy Panel.

For more information on the C_4SE see our website: www.c4se.com

Ontario Energy Board

Ontario

VT INCEPIT FIDELIS SIC PERMANET

IN THE MATTER OF:

A REPORT ON THE DEMAND-SIDE MANAGEMENT ASPECTS OF GAS INTEGRATED RESOURCE PLANNING FOR:

THE CONSUMERS' GAS COMPANY LTD.
CENTRA GAS ONTARIO INC. AND
UNION GAS LIMITED

E.B.O. 169-III

REPORT OF THE BOARD

JULY 23, 1993

Pour des renseignements en français, veuillez communiquer avec la Commission de l'énergie de l'Ontario.

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à frais virés.)

**Ontario
Energy
Board**

Ontario

IN THE MATTER OF:

A REPORT ON THE DEMAND-SIDE MANAGEMENT ASPECTS OF GAS INTEGRATED RESOURCE PLANNING FOR:

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E.B.O. 169-III

REPORT OF THE BOARD

JULY 23, 1993

EXECUTIVE SUMMARY
Report of the Ontario Energy Board
E.B.O. 169-III

During November and December of 1992, the Ontario Energy Board ("the Board") held an oral hearing on the generic issues involved in the demand-side management ("DSM") aspects of integrated resource planning ("IRP"). After evaluating the evidence and arguments submitted by the parties, the Board endorsed the need for formalized DSM planning by each of the three major gas utilities in Ontario, and concluded that these companies should implement their DSM plans as soon as possible. The Board's Report is attached.

Background

In its 1990 Decision in E.B.R.O. 462, the Board decided to call a generic hearing into Least Cost Planning or IRP. In preparation for the hearing, the Board's Technical Staff ("Board Staff") developed a draft list of issues in consultation with the three major gas utilities in Ontario, and comments on these issues were solicited from a broad range of interested parties. After reviewing the responses and consulting with the utilities, the Board determined that a discussion paper should be produced. Accordingly Board Staff, with the assistance of a consultant, prepared a draft report which was also circulated for comment. A final document, entitled "Report on Gas Integrated Resource Planning" ("the Discussion Paper"), was released by the Board in September, 1991.

On October 23, 1991, the Board requested written submissions from the Ontario gas utilities and other interested parties on the issues raised in the Discussion Paper. Forty-one parties responded to the Board's Notice of Hearing and were listed as intervenors in the E.B.O. 169 proceedings. Nineteen of these parties filed written submissions in response to the Discussion Paper.

After reviewing the responses, the Board announced that it would proceed using a building-block approach, starting with an investigation of the DSM issues, before considering supply-side issues and the integration of all aspects of IRP. The Board also stated that the issue of fuel switching would be deferred until the supply-side review.

To facilitate the DSM review, the Board encouraged the parties to reach consensus and reduce the scope and number of contentious issues to be dealt with at the hearing. This settlement phase of the proceedings consisted of two technical conferences to clarify DSM issues and consolidate the positions of the parties. During the conferences, the parties identified a list of DSM issues ("the Demand-Side Issues List") and submitted their positions on each issue. These positions were compiled in a consensus position summary and entered as evidence in the oral hearing.

During the oral hearing, all parties were given an opportunity to present evidence and expert testimony, and to cross-examine the witnesses brought forward by other parties. The utilities were heard first, followed by associations, municipalities and interest groups. At the conclusion of the oral hearing, in addition to their arguments, the parties submitted executive summaries of their positions which have been attached to the Report as Appendix "A".

Board Findings

The Board's guidelines for the implementation of demand-side management of natural gas in Ontario are set out in Chapter 15 of the Report. These guidelines are provided to assist the utilities in the development and implementation of their DSM plans. They address each of the major issues identified in the Demand-Side Issues List and are supplemented by specific conclusions on each issue, as described in Chapters 3 to 14. These conclusions are summarized below.

On the issue of the appropriate costing methodology for DSM, the Board determined that long-term avoided supply-side costs should be used, including avoided upstream tolls and demand charges. All other upstream costs should be identified, if known, but not included in the avoided cost calculations.

With regard to cost-effectiveness tests, the Board described an iterative screening process which it expects the utilities to follow when developing their DSM portfolios. This process incorporates the Societal Cost Test ("SCT") and Rate Impact Measure ("RIM") test. (These tests and other terms are defined in the Glossary which is Appendix "B" to the Report.) Programs which pass the SCT but fail the RIM test must pass a third test to ensure that any related rate impacts would not be excessive and that indirect costs would not exceed the net benefits of a program. Programs which fail the third test are to be evaluated once more before being discarded or deferred. All programs should be assessed quantitatively and qualitatively to determine the best candidates for a utility's DSM portfolio. All prospective programs must pass the SCT, but failure to pass the RIM test would not necessarily eliminate a program.

The Board concluded that those program externalities which involve significant environmental and social costs and benefits should be included in the cost analysis of DSM programs. When evaluating these externalities, the utilities are expected to use the Cost-of-Control method until the Damage Costing method is developed further. To expedite the evaluation process, the Board endorsed a consultative approach which would involve a diverse and non-duplicative Collaborative with a manageable number of participants. The purpose of the Collaborative would be to assess externalities and monetization methodologies and to recommend appropriate qualitative assessment processes for the screening of DSM programs and portfolios. It is expected to strive to issue a final report by February 28, 1994.

After reviewing the issue of the regulatory treatment of DSM investments, the Board determined that approved DSM costs should be treated consistently with prudent supply-side costs. Long-term DSM investments should be included in rate base and short-term expenditures expensed as part of the utility's cost of service. Any variance between the forecast and actual costs or benefits of a DSM program, which occurs in a test year, will be recorded in a deferral account for disposition at the utility's next rates case.

With regard to the question of who should pay for DSM, the Board concluded that the beneficiaries of a program should pay the direct costs of the program to the extent possible. However, customer contributions should not unduly restrict program participation or induce switching to less desirable fuels. Some level of cross-subsidization and rate impact may be acceptable to the Board, but the utilities should make every effort to work toward developing self-sustaining programs.

The Board did not see a need to require utility incentives or decoupling at this time. If utility incentives are shown to be required, the Board preferred the approach of shared savings, based on the nature or urgency of the program, the market being targeted and the degree of difficulty in program implementation.

The Board concluded that full decoupling was currently an inappropriate mechanism for use in Ontario. However, if a utility considers that a lack of revenue protection is a significant disincentive, it may propose a revenue adjustment mechanism, as differentiated from full decoupling, provided the impacts that the mechanism has on the utility's risk exposure and earnings are also considered.

The Board cited a need for effective monitoring and evaluation as a requisite to the efficient development and implementation of the utilities' DSM programs. As part of the evaluation process, the utilities are required to provide a base case forecast of their demand which will act as a benchmark when assessing the performance of subsequent DSM programs and portfolios. The base case should include all DSM programs started prior to the utility's fiscal 1995 test year. Natural Gas for Vehicles programs are to be included in the base case, and excluded from the DSM portfolio. Forecasts should also be provided for each DSM program and the overall portfolio showing the pessimistic, optimistic and most likely impacts relative to the base case forecast, based on achievable potential.

With regard to rate design, the Board concluded that there was little current justification for revising the utilities' rate structures. However, the Board recommended that energy efficiency impacts should be considered in any future review of rate design. The Board stated that the utilities should undertake, and periodically update, assessments of the impacts of interruptible rates on system costs and the use of alternate fuels. The Board also called for the provision of more explicit billing information to customers.

On the issue of jurisdiction, the Board concluded that the utilities should not delay or limit the DSM efforts pending a full resolution of jurisdictional issues. The Board also concluded that it has sufficient jurisdiction under the Ontario Energy Board Act to review DSM plans and to issue guidelines to the utilities. The Board indicated that it fully expects that, as IRP evolves in Ontario, the need for, nature and extent of appropriate legislative amendments will become clearer. The experience gained in the consideration of DSM planning in rates cases will furnish valuable guidance for any future legislative change.

On the issue of funding for the proposed Collaborative, the Board noted that it does not have jurisdiction under the Intervenor Funding Project Act to award advance funding prior to the filing of a specific application. Accordingly, the Board concluded the utilities should directly finance the consultative process. The Board stated that it is confident that prudently incurred consultation costs will be fairly considered for inclusion in the utility's cost of service by subsequent rates panels.

The Board asked the utilities to present their DSM plans no later than as part of their filings for their fiscal 1995 rates cases. In developing their plans, the utilities are encouraged to consult with appropriate parties and to use delivery channels such as those available through the energy service companies in Ontario. Where appropriate, programs should be designed to consider all energy conservation possibilities rather than just focussing on natural gas opportunities.

Once the utilities' DSM plans are implemented and sufficient experience is gained, the Board stated that it expects to proceed with a review of the utilities' supply-side policies, activities and expenditures, as well as the current policies on system expansion, to confirm that these are consistent with least-cost planning principles. Once the supply-side assessment is completed, the Board can proceed with the final phase of the IRP proceedings, i.e. the combination of DSM and supply-side management into an integrated resource plan.

In the interim, the Board recommended that government consider: regulation to establish carbon dioxide emission targets; further development of standards and fiscal measures to improve energy efficiency; establishment of a regulatory mandate for IRP; and clarification of the roles of government agencies to effectively coordinate IRP in all energy sectors.

The Board concluded that overall, notwithstanding the lively debate on many of the issues, it is encouraged by the apparent unanimity among the participants in the IRP proceeding on the underlying principles and objectives of the demand-side management of natural gas in Ontario.

July, 1993

E.B.O. 169-III

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1990, c.O.13;

AND IN THE MATTER OF section 13(5) of the said Act;

AND IN THE MATTER OF a hearing to inquire into, hear and determine certain matters relating to Integrated Resource Planning on the distribution systems of The Consumers' Gas Company Ltd., Union Gas Limited and Centra Gas Ontario Inc.

BEFORE: Marie C. Rounding
Chair and Presiding Member

Carl A. Wolf Jr.
Member

Judith C. Allan
Member

Judith B. Simon
Member

REPORT OF THE BOARD

July 23, 1993

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1. INTRODUCTION AND BACKGROUND

1.0.1 In its April 9, 1990 Decision in E.B.R.O. 462 (the Union Gas Limited 1991 test year rates case), the Ontario Energy Board ("the Board") decided to call a generic hearing into Least Cost Planning. The Board stated that:

> Managing demand in the context of utility expansion in Ontario is a matter of interest to the Board. The Board is also of the view that Least Cost Planning, in its widest sense, must include the environmental aspects raised by Energy Probe as well as minimizing gas leakage and the subject of NGV [natural gas for vehicles].

1.0.2 In the same Decision, the Board also stated its intention to consult with the Ontario gas utilities and other interested parties as to the form of the generic hearing.

1.0.3 Following the E.B.R.O. 462 Decision, the Technical Staff of the Board ("Board Staff") developed, on behalf of the Board, a draft list of issues in consultation with the three major Ontario gas utilities. During this consultation, it was determined that the subject of the generic hearing should be renamed "Integrated Resource Planning" or "IRP". The Board, by a letter dated September 25, 1990, requested comments from a broad range of interested parties on this draft list of issues. Again, in consultation with the major gas utilities, the Board determined that it would initiate the investigation into IRP by producing a discussion paper based on the draft list of issues.

1.0.4 With the assistance of MSB Energy Associates Inc., Board Staff prepared such a draft discussion paper on behalf of the Board. After circulating the draft report for comments, the final document entitled "Report on Gas Integrated Resource Planning" ("the Discussion Paper") was released by the Board in September, 1991.

1.0.5 On September 13, 1991, pursuant to subsection 13(5) of the Ontario Energy Board Act ("the Act") the Board issued a Notice of Hearing into the matter of Integrated Resource Planning under Board File No. E.B.O. 169. The purpose of the Notice was to seek the public's comments in regard to the Discussion Paper as it applies to the natural gas distribution systems of the three major gas utilities in Ontario: The Consumers' Gas Company Ltd., Union Gas Limited and Centra Gas Ontario Inc. The Notice indicated how a party could participate in the proceedings by becoming an intervenor and also outlined the procedure for intervenors to apply for funding under the Intervenor Funding Project Act, R.S.O. 1990, I.13 ("the IFP Act").

1.0.6 On October 23, 1991, the Board issued Procedural Order E.B.O. 169 No. 1 whereby, among other things, the Board solicited written submissions by the Ontario gas utilities and other interested parties regarding the issues raised in the Discussion Paper. Since this is a generic proceeding, the Board indicated that it would not examine specific utility, conservation or environmental proposals in this hearing. The preparation and submission of written responses to the Discussion Paper was subsequently designated as Phase I of the E.B.O. 169 proceedings ("Phase I").

1.0.7 The following parties answered the Board's Notice of Hearing and were listed as intervenors in the E.B.O. 169 proceedings:

- Alberta Petroleum Marketing Commission
- ANR Pipeline Company
- Association of Major Power Consumers in Ontario ("AMPCO")
- Beak Consultants Limited
- Canadian Association of Energy Service Companies ("CAESCO")
- Canadian Petroleum Association (now Canadian Association of Petroleum Producers)
- Centra Gas Ontario Inc. ("Centra")
- Centra Gas Manitoba Inc.
- The Coalition of Environmental Groups for a Sustainable Energy Future ("the Coalition" or "CEG")
- The Consumers' Gas Company Ltd. ("Consumers Gas")
- Consumers' Association of Canada (Ontario) ("CAC(O)")
- Direct Energy Marketing Limited ("Direct Energy")
- ECNG Inc.
- Ecosystem Approach Group ("EAG")
- Energy Brokers Canada Inc.
- Energy, Mines and Resources, Canada
- Energy Probe
- Gaz Métropolitain, inc. ("GMi")
- INCO Limited ("INCO")
- Industrial Gas Users Association ("IGUA")
- The City of Kitchener
- Mobil Oil Canada
- Municipal Electric Association ("MEA")
- Mutual Gas Association
- None Too Soon
- North Canadian Marketing Inc.
- Northridge Petroleum Marketing Inc. ("Northridge")
- NOVA Corporation of Alberta
- Ontario Association of Physical Plant Administrators
- Ontario Hydro
- Ontario Métis and Aboriginal Association ("OMAA")
- Pollution Probe
- A.E. Sharp Limited
- Rainer W. Stahlberg
- The City of Toronto

- TransCanada PipeLines Limited ("TCPL")
- TWG Consulting Inc.
- Unigas Corporation
- Union Gas Limited ("Union")
- Thomas Vladut
- Western Gas Marketing Limited ("WGML")

1.0.8 The following parties filed written submissions or comments in response to the Discussion Paper:

- AMPCO
- CAC(O)
- CAESCO
- Centra
- The Coalition
- Consumers Gas
- Direct Energy
- Energy Probe
- IGUA
- INCO
- The City of Kitchener
- MEA
- Northridge
- OMAA
- Ontario Deputy Minister of Energy
- Ontario Hydro
- Pollution Probe
- The City of Toronto
- Union

1.0.9 By Procedural Order E.B.O. 169-II No. 1, dated May 26, 1992, the Board announced that it would proceed via a "building block" approach whereby demand-side management ("DSM") issues would be investigated before considering supply-side management issues and, subsequently, the integration of all aspects of IRP. The Board also decided that the issue of fuel switching and its potential application to DSM would be considered at a later date as part of the review of the supply-side aspects of IRP.

1.0.10 To facilitate the proceedings, the Board established a process designed to encourage consensus and reduce the scope and number of contentious issues to be dealt with at the hearing. Therefore, as the second phase in the proceedings ("Phase II"), the Board announced its intention to hold two technical conferences to clarify DSM issues and consolidate the positions of the parties.

1.0.11 The two technical conferences were held, in the absence of the Board panel, on August 4-7 and September 21-24, 1992. The purpose of the first conference was to allow participants to state their positions and to better understand the positions put forward by the other parties regarding DSM options. At the meeting, presentation of the parties' summary statements was followed by an open discussion of the issues. A verbatim transcript of the first technical conference is available for public review at the Board's offices.

1.0.12 Following the first conference, and pursuant to Procedural Order E.B.O. 169-II No. 2, dated July 9, 1992, Board Staff circulated a summary document which grouped the various views of the parties into preliminary consensus positions. The parties were asked to comment on the consensus positions listed in the summary document so that their comments could serve as a basis for discussion at the second technical conference.

1.0.13 By the same Procedural Order, the parties were also required to submit a summary of their positions on the list of DSM issues ("the Demand-Side Issues List"), which is appended to that Order. Those submissions are also available for public review at the Board's offices.

1.0.14 The purpose of the second technical conference was to finalize the consensus positions of the parties using a consultative process. The parties were also asked to consider whether the issues on the Demand-Side Issues List should be refined. The second technical conference was not transcribed in order to facilitate a more open discussion of the issues.

1.0.15 At the conclusion of the second technical conference, the parties submitted their consensus position statements on the Demand-Side Issues List. These were compiled and issued to all participants on October 13, 1992. The consensus position summary ("the Consensus Summary") has been entered as evidence in the oral hearing of the demand-side issues in Integrated Resource Planning under Board File No. E.B.O. 169-III ("Phase III").

1.0.16 Board Staff took no position on the issues during either Phase I or Phase II of the proceedings.

1.0.17 Procedural Order E.B.O. 169-II No. 3, dated September 15, 1992, (subsequently renamed Procedural Order E.B.O. 169-III No. 1) fixed the date for the commencement of the oral hearing of DSM issues as Monday, November 9, 1992.

2. THE PHASE III PROCEEDING

2.0.1 The oral portion of the E.B.O. 169 Phase III hearing commenced on Monday, November 9 and concluded on December 8, 1992. During the hearing, all parties were given an opportunity to present evidence and expert testimony, and to cross-examine the witnesses brought forward by other parties. In general, each party was cross-examined in turn on all issues on the Demand-Side Issues List. The utilities were heard first, followed by associations, municipalities and interest groups.

2.0.2 During Phase III, Board Staff acted as an active party to the proceeding, and took positions on the issues on the Demand-Side Issues List. Other than cross-examining on a broad basis to assure a complete record, Board Staff acted autonomously. Board Staff did not call witnesses during the oral hearing.

2.0.3 Following the completion of the oral hearing, the active parties were directed to file argument-in-chief by December 23, 1992 and reply argument by January 22, 1993. The parties were asked to provide, in their arguments, their positions on each of the issues contained in the Demand-Side Issues List, as well as their recommendations on how the Board should proceed with the implementation of IRP and the guidelines it should consider.

2.0.4 Because E.B.O. 169 was a generic hearing convened at the Board's request, no specific party was identified as the applicant. Consequently, all parties were given the opportunity to reply to the arguments-in-chief submitted by the other parties.

2.0.5 In addition to their arguments, the parties submitted Executive Summaries of their positions, as directed by the Board. These Executive Summaries are attached as Appendix "A". A Glossary of Terms used in this Report is attached as Appendix "B".

2.1 APPEARANCES

2.1.1 The parties and their representatives who actively participated in the oral hearing were as follows:

Board Staff	I. Blue J. Lea
CAESCO	J.T. Brett
Centra	P. Jackson M. Penny
The Coalition	D. Poch K. Millyard
CAC(O)	R. Warren P. Lefebour
Consumers Gas	R.J. Howe
Energy Probe	M.O. Mattson T. McClenaghan N. Rubin
Farm Energy Association*	I. Mondrow

The City of Kitchener	A. Ryder
OMAA	M. Omatsu
Pollution Probe	M. Klippenstein
The City of Toronto	H. Poch
Union	B. Kellock

* At the commencement of the Phase III hearing, Mr. Mondrow indicated that the intervention of R.W. Stahlberg would now go forward under the name of the Farm Energy Association.

2.2 WITNESSES

For CAESCO:

A.W. Levy	President, CAESCO
J. Walrod	Principal, XENERGY Inc.

For Centra (Employees):

R.M. Bell	Manager, Environmental Affairs
J. Peverett	Manager, Corporate Planning
D.J. Gallagher	Manager, Marketing
R.W. Reid	Director, Gas Supply
P.J. Hoey	Manager, Regulatory Affairs

For the Coalition:

P.L. Chernick	President, Resource Insight, Inc.
W.B. Marcus	Principal Economist, JBS Energy Inc.

For CAC(O):

G. Edgar	Executive Director, Wisconsin Energy Conservation Corporation
P. Dyne	Chair, Energy Committee, Consumers' Association of Canada
C. Gates	Consultant, REIC (Consulting) Ltd.

For Consumers Gas (Employees):

W.B. Taylor	Director, Financial and Economic Studies
H.M. Lavergne	Director, Rates and Regulatory Proceedings
J.R. Hamilton	Director, Marketing Administration

For Energy Probe:

L. Ruff	Managing Director, Putnam Hayes and Bartlett Inc.
T. Adams	Utility Analyst, Borealis Energy Research Association

For Farm Energy Association:

R.W. Stahlberg	Principal, Farm Energy Association

J. Johnson	President, Canadian Renewable Fuels Association
For OMAA:	
R. Swain	President, OMAA
M. Watkins	Professor, Economics and Political Science, University of Toronto
I. Goodman	Principal, The Goodman Group, Ltd.
For Pollution Probe:	
J. Gibbons	Senior Economic Advisor, Canadian Institute of Environmental Law and Policy
For the City of Toronto:	
D. Harvey	Associate Professor, Department of Geography, University of Toronto
For Union (Employees):	
P. Shervill	Manager, Environmental Affairs
E. Merritt	Manager, Regulatory Projects
J. van der Woerd	Manager, Marketing
D.D. Bailey	Manager, Financial Studies
For Union (Other):	
M. Lerner	President, Energy and Environmental Analysis Inc.

For Centra and Union:

R.S. Bower	Professor Emeritus, Finance and Managerial Economics, Amos Tuck School of Business Administration, Dartmouth College
V.L. McCarren	Assistant to the President, Special Projects, University of Vermont

2.2.1 A transcript of the public hearing and copies of all exhibits and submissions are on file for review at the Board's office.

2.2.2 While the Board has taken account of all the evidence and submissions on the issues in these proceedings, it has in this Report only summarized these to the extent needed. Because of the high level of interaction among the issues, parties, in their submissions, sometimes stated positions on one issue as part of their submissions under another issue. To the degree possible, the Board has attempted to amalgamate all the submissions on a particular issue under that issue.

2.2.3 The Board allowed the parties to include, in their arguments, submissions on issues beyond the Demand-Side Issues List as "Issue 12 - Other Issues". The Board has combined these submissions into its discussions on the most closely-related issues in the Demand-Side Issues List.

2.2.4 In succeeding chapters, the Board has dealt with each issue on the Demand-Side Issues List and, for the convenience of the reader, directly quoted (in italics) the pertinent segment of the Consensus Summary on each issue ("the Consensus Statement"). The Positions of the Parties are then presented, and are followed by Board Findings, which were reached after considering all the evidence and submissions. These findings are then summarized in the form of procedures and guidelines, in Chapters 14 and 15, respectively. The final chapter deals with cost awards.

3. ISSUE 1 APPROPRIATE COSTING METHODOLOGY FOR DEMAND-SIDE OPTIONS

3.0.1 In order to establish a portfolio of demand-side management programs, the first issue to be addressed is the selection of an appropriate methodology to define program costs and benefits in a consistent manner. Only then can candidate programs be compared effectively in order to construct an optimum portfolio.

3.0.2 This issue was included in the Demand-Side Issues List as:

> ***What is the appropriate costing methodology for demand-side options (e.g. avoided/marginal costs of supply-side options such as additional facilities, storage of gas supply)?***

and

> ***To what extent should the utilities use demand-side options when planning to meet their forecast demand?***

3.0.3 In response to the questions listed above, Board Staff, CAC(O), CAESCO, Centra, CEG, Consumers Gas, OMAA, Pollution Probe and Union agreed to the following Consensus Statement. The City of Toronto agreed with paragraphs 1, 3 and 6 of the first six points of the Consensus Statement, and took no position on any other paragraphs of the Consensus Statement on this issue. Energy Probe presented its own position on this issue.

Consensus Statement

1. *The appropriate approach to determining the value of demand-side options is an avoided cost methodology.*

2. *Avoided costs should be calculated on the basis of the cost factors specific to each utility (e.g. load factor) except that it is appropriate that certain avoided costs be uniform between utilities when the costs are undifferentiated between them (e.g. CO_2 emissions).*

3. *Avoided costs include: utility capital, operating and energy supply costs; monetized environmental and societal externality costs; and incremental or decremental customer equipment and operating costs.*

4. *Avoided costs should be time-differentiated (e.g. annual, seasonal, monthly and/or daily; peak day) and system-differentiated. A "single valued" avoided cost approach is not considered adequate.*

5. *Avoided costs should be determined over the useful life of the DSM technology. It is recognized that uncertainty concerning the level of avoided costs will increase as the forecasting horizon lengthens.*

6. *Avoided externality costs should be included in the appropriate cost-effectiveness tests to the extent that these costs have been satisfactorily monetized. Externality costs which have not been monetized should be considered qualitatively during the cost-effectiveness screening of DSM measures or programs.*

7. *Different costs will be used in different cost-effectiveness tests as described in the definitions of cost-effectiveness tests at Issue 2.*

There are two ways in which this issue [To what extent should the utilities use demand-side options when planning to meet their forecast demand?] can be interpreted. The first perspective is how extensively the utilities should use demand-side options, in conjunction with supply-side options, in meeting their forecast demand. The second perspective is how the utilities should incorporate the effect of DSM programs into their demand forecast. Therefore, the following points address both perspectives.

1. *In terms of meeting future demand, DSM options should be given equal consideration as supply-side actions, and DSM initiatives should focus on barriers to wise energy use in a manner which provides valued services.*

2. *Supply plans should be based on the expected impact of DSM programs rather than a theoretical demand reduction target or goal. The expected results of DSM programs must have a corresponding impact on supply-side plans.*

3. *DSM programs which have passed the appropriate cost-effectiveness tests and form part of the utility's rate case proposal should be included in a utility's base case demand forecast. It is recognized that forecasting the volumetric effects of certain DSM programs involves significant uncertainties, so the utility's base case supply plan should be flexible enough to accommodate reasonable variance between forecast and actual DSM program results.*

4. *In certain cases utilities can rely on existing experience when forecasting DSM program effects, while in other cases it may be necessary to test-market programs initially in order to obtain more information. The expected volumetric effects of all adopted DSM*

programs, including test-marketed programs, should be included in the utility's demand forecast.

Positions of the Parties

3.0.4 Board Staff submitted that avoided costs provide the only practical means of comparing DSM programs. While Board Staff agreed that the use of avoided costs would also permit comparisons to supply-side options, it pointed out that to date only positive externalities (i.e. beneficial externalities such as increases in employment) have been considered in supply-side tests.

3.0.5 In addition to the avoided costs described in the Consensus Statement, Board Staff submitted that avoided costs upstream of the utility system and unabsorbed demand charges should also be included in the DSM avoided cost analysis. According to Board Staff, the use of long-run avoided costs as inputs for the cost-effectiveness tests would allow the utilities to evaluate their DSM programs and compare them fairly with supply-side options. Board Staff claimed that a DSM option would be valuable only if it reduced a utility's supply-side requirements.

3.0.6 While CAESCO agreed that the value of a DSM option should be based on avoided costs, it argued that this amount may exceed the direct value to the customer. It claimed that using avoided costs would hamper the efforts of energy service companies ("ESCOs") to structure DSM contracts on the basis of the direct value to the end user.

3.0.7 Centra agreed with Board Staff that the appropriateness of a DSM option will depend on a utility's unique system, gas supply characteristics and avoided costs. Centra argued further that marginal avoided costs were the most appropriate measure of incremental costs and benefits.

3.0.8 Centra disagreed with Board Staff's submission that forecast and actual avoided costs should be monitored on an on-going basis, since Centra's avoided costs would be calculated over a 10-year time frame and would vary by delivery area, load impact and supply-side alternative.

3.0.9 With regard to the inclusion of upstream avoided costs, Centra argued that only increased transportation rates and demand charges should be included, since these are costs which would in fact be avoided.

3.0.10 On the issue of the most appropriate time frame for the avoided cost analysis, Centra argued that the evaluation period should be the same as the expected life of the DSM program.

3.0.11 CEG argued that all DSM programs which are less costly than supply alternatives should be pursued. It rejected Union's submission that a DSM portfolio must not result in an increase in rates. The Coalition contended that such a policy would restrict the development of DSM, and lead to "cream-skimming" and lost opportunities.

3.0.12 The City of Kitchener disagreed with the Consensus Statement because it believed that the appropriate costing methodology should not be limited to avoided costs, but should also include the direct costs of a DSM program. While the City of Kitchener contended that the most appropriate costing methodology should include both costs and benefits, it argued that the benefits of externalities which were outside the utility's control should not be considered.

3.0.13 Energy Probe contended that the most appropriate measure of the net benefit, and indeed the only viable evaluation method, of a DSM program was a participant's willingness to pay, since individual customers are the best experts on what is of value to them. Energy Probe further submitted, and Board Staff concurred, that the avoided cost must reflect the marginal cost of supplying gas to each customer.

3.0.14 OMAA submitted that a full range of externalities, and in particular any social externalities, should be incorporated in the avoided costs of a DSM program. Its position was that all relevant external costs associated with the production, transportation and consumption of natural gas should be taken into account.

3.0.15 In its reply, OMAA submitted that the concerns raised by the City of Kitchener, regarding the inclusion of direct costs, were inappropriate since the costing methodology recommended in the Consensus Statement refers only to the benefits of avoiding unnecessary supply costs.

3.0.16 Although Union endorsed the Consensus Statement, it observed that its avoided costs are relatively low and, therefore, it submitted that each utility's particular circumstances should be considered when evaluating DSM options. While Union recognized that demand-side options should receive the same consideration in meeting demand as supply-side options, it emphasized that demand-side options differ fundamentally from supply-side options in that they provide special benefits to distinct customer groups, rather than providing a consistent level of service to all customers.

3.0.17 In its reply, Union submitted that a local distribution company ("LDC") should use its average avoided cost to evaluate programs since it is not possible or appropriate to "stream" costs to specific customers. Union also added that avoided costs must be adjusted frequently to accurately reflect changes in a utility's supply plan.

3.1 BOARD FINDINGS

3.1.1 In general, the Board endorses the Consensus Statement regarding avoided costs and costing methodologies. The Board concurs that avoided supply-side costs, including capital, operating and energy costs, should be used when measuring the benefits of natural gas DSM programs. The Board also concurs with the inclusion of demand-side costs such as incremental or decremental customer equipment and operating costs. However, the Board believes that attempts to incorporate the "upstream" avoided costs of TCPL and natural gas producers would impose an added layer of complexity to an already intricate problem. It is doubtful that the Ontario gas utilities now have the ability to accurately assess those upstream costs that are beyond the jurisdictional reach of the Board. However, the Board acknowledges that the full impacts of DSM measures will influence upstream activities.

3.1.2 The Board has concluded that, based on the current evidence before it, avoided upstream costs should be excluded from avoided cost calculations. However, where such costs are known they should be identified at the time that DSM programs are proposed.

3.1.3 While storage and transportation tolls and demand charges are costs which are incurred upstream, they are direct costs to a gas utility which are known and calculable. The Board sees merit in including any impacts that DSM may have on these costs when assessing avoided costs.

3.1.4 The Board concurs with the evidence of Dr. Lerner that there are significant differences between gas and electric utility costs. The Board cautions that these differences make it perilous to rely too heavily on electric utility models and experience as a basis for gas DSM planning.

3.1.5 The Board notes that experience with gas DSM is limited, and it has yet to be fully evaluated in any jurisdiction in Canada or elsewhere. Thus, there must be sufficient flexibility when assessing avoided costs to react to the experience gained as utilities proceed along their learning curves, and to accommodate the differences between individual gas utilities in Ontario.

3.1.6 The Board accepts that it is necessary that long-run avoided costs be considered when determining the net present value of DSM programs over their useful life. However, the likelihood of changes in the economy, in the relative prices of alternative fuels and in the levels of customer acceptance suggests that long-term forecasts are, at best, tenuous. This is compounded by the rapid pace at which new energy-efficient technologies are being developed.

3.1.7 When calculating avoided costs for long-term programs, emphasis should be placed on the performance in the early years of the DSM program and portfolio, since uncertainty in performance increases as the time horizon is extended and because of the disproportionate impact that performance in the early years has on net present value assessments. In general, the Board considers the early years to be the first five years of the DSM program.

3.1.8 In order to compare a program's costs and benefits with those of other DSM programs in an equitable manner, a break-even analysis based on net present values should be carried out for each program. The implications of the results of the break-even analysis for the program and the overall DSM portfolio should be provided.

3.1.9 The matter of how environmental and social costs should be incorporated into avoided cost determinations is dealt with under Issue 3.

4. ISSUE 2 COST-EFFECTIVENESS TESTS

4.0.1 A consistent method of determining the cost-effectiveness of each DSM program is necessary to assess the value of the program and to identify which programs should be considered as candidates for the utility's DSM portfolio. Different cost-effectiveness tests are required to factor in the various types of costs and benefits, and the Board must determine which test or tests are most appropriate.

4.0.2 This issue was included in the Demand-Side Issues List as:

> ***What are the appropriate cost-effectiveness tests (i.e. technical cost test, societal cost test, utility cost test, etc.) and methodologies to be used for demand side options? What costs should be included in this cost-effectiveness analysis? Should the E.B.O. 134 feasibility analysis be applied, and what modifications, if any, would be required?***

4.0.3 The Board's E.B.O. 134 Report, dated June 1, 1987, described the economic feasibility tests to be used in the analysis of supply-side options, e.g. transmission and distribution system expansions. The Board has appended the pertinent findings from that Report as Appendix "C".

4.0.4 In response to the questions on cost effectiveness, Board Staff, CAC(O), CAESCO, Centra, CEG, Consumers Gas, Pollution Probe and Union agreed to the following Consensus Statement. In argument, Energy Probe urged the Board not to adopt the Consensus Statement on this issue as Board policy.

Consensus Statement

The proposed methodology and set of cost-effectiveness tests to be used to evaluate demand-side management programs include the following criteria:

a) All DSM programs should be expected to pass the Societal Cost Test.

b) DSM programs under consideration that pass the Societal Cost Test and pass the Rate Impact Measure Test should be approved provided all reasonable steps to prevent lost opportunities have been taken and the programs do not violate any other more important utility or public interest objectives (examples might include system reliability or safety).

c) DSM programs that pass the Societal Cost Test but do not pass the Rate Impact Measure Test (not financially sustaining) should be approved providing the following conditions are met:

i) The resulting rise in rates after evaluating all programs in the DSM portfolio must not impose an undue burden on existing customers. Both short-term and long-term rate impacts should be considered;

ii) The resulting rise in rates must not entail second round net social costs that are expected to exceed the first round net social benefits of the demand management program (e.g. if higher rates cause customers to switch away from gas, the *resulting net social costs could exceed the net social benefits of the program that is being financed by the higher rates);*

iii) *Customer contributions are appropriate to the extent that they do not seriously reduce overall participation or foreclose the participation of specific customer groups (examples might include low-income groups or rental customers). The Participant Test is one factor to be considered in establishing appropriate levels of contribution.*

iv) *Financially non-sustaining DSM programs may be included in the DSM portfolio. They will be considered on the basis of such factors as their social cost-effectiveness, a desire to maximize the breadth and quality of the conservation, preventing lost opportunities, and the desire to offer a broad menu of demand management programs.*

The proposed evaluation process embraces the basic concepts established in E.B.O. 134, but introduces a new screening mechanism, plus added considerations and perspectives which are relevant to DSM programs.

Definition of Cost-Effectiveness Tests

The Societal Test incorporates all costs and benefits arising from the adoption of a program. These would include all direct costs borne by the utility such as commodity, transportation, storage, load-balancing, and distribution costs as well as system expansion costs. Also utility costs such as incremental administration, maintenance, and participant incentive costs would be recognized. In addition, all participant costs (net of incentives) should be included. In the case of programs that affect consumption of more than one fuel, all avoided costs of all fuels would be recognized. Finally, all externalities, including environmental and societal externalities, *would be included. Externalities which cannot be monetized should be treated qualitatively.*

Thus the Societal Test considers all costs and benefits accruing to society as a whole, and is not limited to the utility and its customers.

The benefits in the Societal Test are the reduction in energy supply costs (including externalities) plus any customer equipment and operating costs avoided by the participant due to the program. The costs are any increases in energy supply costs (including externalities) plus all of the program costs paid by either the utility or the participant.

The Total Resource Cost Test comprehends all costs and benefits included in the Societal Test, with the exception of externalities. The benefits and costs of the Societal Test are used except for environmental and societal externality benefits or costs.

The Participant Test includes only those costs and benefits borne by the participant, which could comprise capital, installation, and operating and maintenance costs, offset by energy cost savings measured at the rate paid by the participant, net of utility incentives.

The benefits include reductions in energy bills, incentives, and customer equipment and operating costs due to participation in the program. Costs include any increases in energy bills and out of pocket expenses that the customer pays to participate in the program.

The Rate Impact Measure Test (also referred to as the RIM Test or Non-Participant Test) includes all direct and indirect costs and benefits accruing to the utility mentioned under the Societal Test but also includes the reduced revenues collected by the utility as a result of energy savings. It therefore measures the impact of DSM programs on the utility's rates.

Benefits considered in the RIM Test are the reduction in utility supply costs and any increases in revenues. The costs are any increases in utility supply costs, revenue losses, program costs paid by the utility and any incentives paid to the participants.

The Utility Test is identical to the RIM Test, except that it does not factor in lost revenues due to DSM programs. It measures the relative impact of DSM programs on the utility's revenue requirements as a result of changes in cost.

The benefits in this test are the reductions in utility supply costs. The costs are any increases in utility supply costs, the program costs paid by the utility, and any incentives paid to the participants.

Positions of the Parties

4.0.5 Board Staff supported the use of cost-effectiveness tests which take into account a broad range of public interest factors and protect against an undue burden being placed on existing customers. The primary concern of Board Staff was the maintenance of reasonable rates for existing gas consumers. Board Staff contended that DSM rate impacts should not be greater than the rate impact that would have resulted from the alternative supply option, and that rate impacts should be minimized by selecting the least-cost option in all cases.

4.0.6 According to Board Staff, the portfolio approach is the most effective means of ensuring that a broad range of DSM programs are offered to all classes of customers. It stated that while a DSM portfolio should not be required to pass the Rate Impact Measure ("RIM") test, it should also not place an undue burden on any customer or customer class. However, Board Staff agreed that some amount of cross-subsidization is unavoidable, although it should be limited to reasonable levels.

4.0.7 Board Staff asked the Board to indicate whether the DSM cost-effectiveness tests should be applied in a consistent manner with the E.B.O. 134 supply-side tests, which consider both qualitative and quantitative externalities but do not recognize externalities which have negative impacts. It further submitted that, should the Board so desire, the framework for demand-side options can be used to refine or supplement the E.B.O. 134 methodology.

4.0.8 In the opinion of Board Staff, customer contributions are appropriate for DSM programs, as they could make financially non-sustaining DSM programs more profitable, and thereby reduce the need for a subsidy from non-participants. To be consistent, contributions should also be sought for fuel substitution programs, as well as other supply-side programs such as transmission projects. Wherever possible, the utility should strive to have a program pass the RIM test or have a minimum benefit/cost ratio of one.

4.0.9 CAESCO's position was that DSM programs should pass both the societal and ratepayer impact tests. CAESCO expressed concern that incentive levels may be unnecessarily high if programs are undertaken that do not pass a RIM test but pass a societal cost test, since Societal Cost Test ("SCT") evaluations may be driven by arbitrarily derived monetization factors. In most U.S. jurisdictions where IRP has been implemented, it is the Total Resource Cost ("TRC") test that is the ultimate determinant, and the SCT is used only in the initial screening process.

4.0.10 CAESCO submitted that all customer classes should have the opportunity to participate in the utility's portfolio of DSM programs. ESCO-linked programs, which focus on institutional, industrial and commercial customers, should be adopted by the utilities along with the programs that have been successful in the residential and small commercial markets. CAESCO advocated that ESCOs and the utilities should work together in the design and implementation of DSM rather than moving forward on parallel paths.

4.0.11 Centra emphasized paragraph (c)(ii) of the Consensus Statement, which cautions that rate increases must not entail second round net societal costs that exceed the first round net societal benefits of the demand management program. This, it claimed, might occur if higher rates cause customers to switch away from gas to less environmentally desirable fuels. Centra stated that the evidence indicates that there is more potential environmental and social benefit in fuel switching than will be realized through gas conservation. Therefore, while DSM action should encourage efficiency, it should not materially discourage fuel switching to gas or encourage fuel switching away from gas.

4.0.12 Centra noted the difficulty in forecasting the effect of price changes on fuel switching; the sensitivity in many markets to small price changes; and the environmental impacts of fuel switching. Because of these factors, it suggested that the degree to which prices should be allowed to increase as a result of a DSM portfolio will be an important limitation in the choice of an appropriate portfolio.

4.0.13 CEG argued that the benefits of aggressive DSM, even if it causes some rate increases, will lead to reduced energy bills and a least-cost energy economy. CEG expressed its support for the Board's ability to make a determination on what constitutes an undue rate impact. While CEG recognized the importance of keeping industrial gas prices competitive, it believed that the threat of the loss of industrial load, as a result of DSM rate impacts, was exaggerated and suggested that negative impacts could be offset by targeting specific DSM measures to industrial customers, and by allocating costs to other rate classes.

4.0.14 In CEG's view, utilities should not simply provide a single preferred plan. Alternatives should be presented in detail. In particular, utilities should identify and assess program alternatives; the cost of each alternative; alternative bundles of activities or measures for each program; alternative measure costs; and the results of the various cost-effectiveness tests for each measure, program, portfolio and any alternatives. CAC(O) indicated that it supported a similar approach, and OMAA agreed with CEG's proposed filing requirements. However, Centra argued in reply that a detailed proposal on filing requirements is premature and that, in any event, the cost of presenting such extensive analyses is likely to be prohibitive.

4.0.15 Consumers Gas agreed with Board Staff that it is appropriate to extend some portion of DSM costs to the system, as all ratepayers will benefit from the avoided costs of future supply, including externality costs. Consumers Gas also agreed that a balanced portfolio of DSM programs is warranted given the existence of significant market barriers to conservation.

4.0.16 Consumers Gas submitted that the analysis of future avoided system costs could reveal significant benefits for gas customers. It also suggested that some upward movement in current rates could be justified in recognition of the fact that current rates are based on a historic rate base which is not adjusted for inflation. Consumers Gas urged the Board to find that potential contributions from the electric power industry, as well as from governments, are appropriate when the results of the cost-effectiveness testing show a large net benefit to future electricity customers or to society in general.

4.0.17 Consumers Gas recommended that the E.B.O. 134 feasibility analysis be modified to be consistent with the DSM analysis, so that the SCT would serve as the primary screening, or Stage 1 test, for both the supply-side and demand-side analyses. Stage 2 would then consist of the RIM test and the Participant Test ("PT"), in order to address such issues as "who pays", cross-subsidization, and the need for customer contributions and/or incentives. Qualitative factors would be considered at Stage 3. Consumers Gas also noted in reply that externality costs must be included in supply options that are evaluated against DSM costs, in order to be consistent with the Consensus Statement.

4.0.18 Energy Probe submitted that the most appropriate cost-effectiveness test for DSM programs is the RIM test and that the SCT cannot be reliably applied or tested for accuracy in the presence of subsidized prices. The four conditions set out in the Consensus Statement under paragraph (c), for approving non-sustaining programs which fail the RIM test, were argued by Energy Probe to be too vague or weak to have any real value in the selection of programs. With regard to condition (c)(iv), Energy Probe endorsed an explicit ranking which would select the programs that produce the greatest social benefit for each dollar of subsidy needed.

4.0.19 Energy Probe did not support a portfolio approach, since offering a broad menu of programs will not transform the net costs of individual programs into an overall net benefit. Energy Probe further submitted that the evidence indicated only a "tiny" potential for "win-win" natural gas conservation in Ontario, "where everybody comes out paying less" than under the alternative supply-side option.

4.0.20 Energy Probe took the position that subsidized DSM measures or programs impose net financial costs on the system, and therefore, it urged the Board not to permit DSM activities that are subsidized by revenues from LDC monopoly activities. Energy Probe expressed its concerns about the negative social, equity and environmental impacts of raising natural gas prices; the regulatory complexity and arbitrariness of judgments about the cost-effectiveness of cross-subsidized measures; and the impacts that subsidized DSM activities might have on the non-monopoly suppliers of DSM goods and services.

4.0.21 Finally, Energy Probe recommended that the Board amend its E.B.O. 134 cost-effectiveness test for supply-side investments to make it more difficult to justify financially non-sustaining investments.

4.0.22 The City of Kitchener supported the staged screening and approval process outlined in the Consensus Statement and argued that subsidization may be appropriate if it is in the general interest of the system and its customers as a whole. It may also be appropriate, in the view of the City of Kitchener, for the portfolio to have some rate impact.

4.0.23 In the opinion of the City of Kitchener, no definition as to what constitutes "undue rate impacts" should be issued by the Board, as the acceptability of rate impacts will depend on the circumstances at the time of each rates case.

4.0.24 It further submitted that the principles which underlie E.B.O. 134 should not be applied to demand-side investment if they permit utilities to justify investment on the basis of incidental benefits which fall outside the mandate to provide utility services on an economic basis. The City of Kitchener also argued that unnecessary investment in utility services encourages an inefficient use of resources which is contrary to IRP principles.

4.0.25 Although the Consensus Statement contained many elements which OMAA could support, OMAA was concerned whether, in practice, externalities would be sufficiently considered in the SCT. Consequently, OMAA was not a party to the Consensus Statement. Moreover, other factors such as lost opportunities, equity, and the need for the sustained and orderly development of efficiency programs should be considered, in addition to the factors in the Consensus Statement's cost-effectiveness tests. Consideration of any of these factors, OMAA maintained, may on occasion justify inclusion of DSM measures that would otherwise be marginally cost-effective.

4.0.26 OMAA suggested that the SCT should be the principal standard in determining whether DSM should be implemented, subject to the considerations described in the Consensus Statement. OMAA argued that the short-term impact of investments in DSM may be negative under the RIM test, but analysis of avoided future system costs could reveal significant benefits, thereby justifying some cross-subsidization from present customers.

4.0.27 In OMAA's view, the utilities should treat ESCOs and other non-utility suppliers of DSM goods and services as strategic allies. The goal, according to OMAA, is to encourage the development of a vibrant DSM marketplace that will sustain a permanent transformation toward greater energy efficiency. While OMAA agreed that utility programs should not cavalierly undercut existing suppliers and markets, it was concerned that an overly restrictive response to these concerns may impede the levels of achievable DSM.

4.0.28 Union submitted that the most important principle underlying the tests to determine the desirability of DSM programs is the need to ensure that all considerations concerning societal, customer and participant impacts are included. The same methodology should be used to assess both DSM and supply-side options. However, rate impacts resulting from supply-side options, which produce benefits for customers as a whole, must be distinguished from rate impacts resulting from DSM program benefits which are enjoyed only by participating customers in targeted customer segments.

4.0.29 Union disagreed with the suggestions that rate impacts due to DSM which exceed the rate impacts of the avoided supply options are of little or no consequence. Union noted that such suggestions were contradicted by experience and published data concerning customer behaviour, and that they ignored the environmental benefits to be achieved by enhancing the competitive position of gas. Union also observed that, since new DSM programs would benefit targeted customer segments, rate impacts could influence perceptions of the overall fairness of the programs, thereby affecting customer response.

4.0.30 Union argued that, given its relatively low avoided costs and its preliminary assessment of new DSM initiatives, there is little chance it can develop a menu of new cost-effective DSM programs which focuses on market barriers and includes something for everyone without a rate impact.

4.0.31 Union argued in reply that its desire to develop a portfolio of DSM programs with no overall rate impact over the life of the project was based on sound principles.

4.1 BOARD FINDINGS

4.1.1 The Board supports a portfolio approach to DSM programs as the most effective means of ensuring that as many as customers as is reasonably possible are afforded the opportunity to participate and share in the benefits of DSM. A portfolio approach would allow groups, that might otherwise be precluded from participating, such as low-income customers, tenants, Aboriginals and farmers to participate in these programs, while minimizing the rate impact on existing customers.

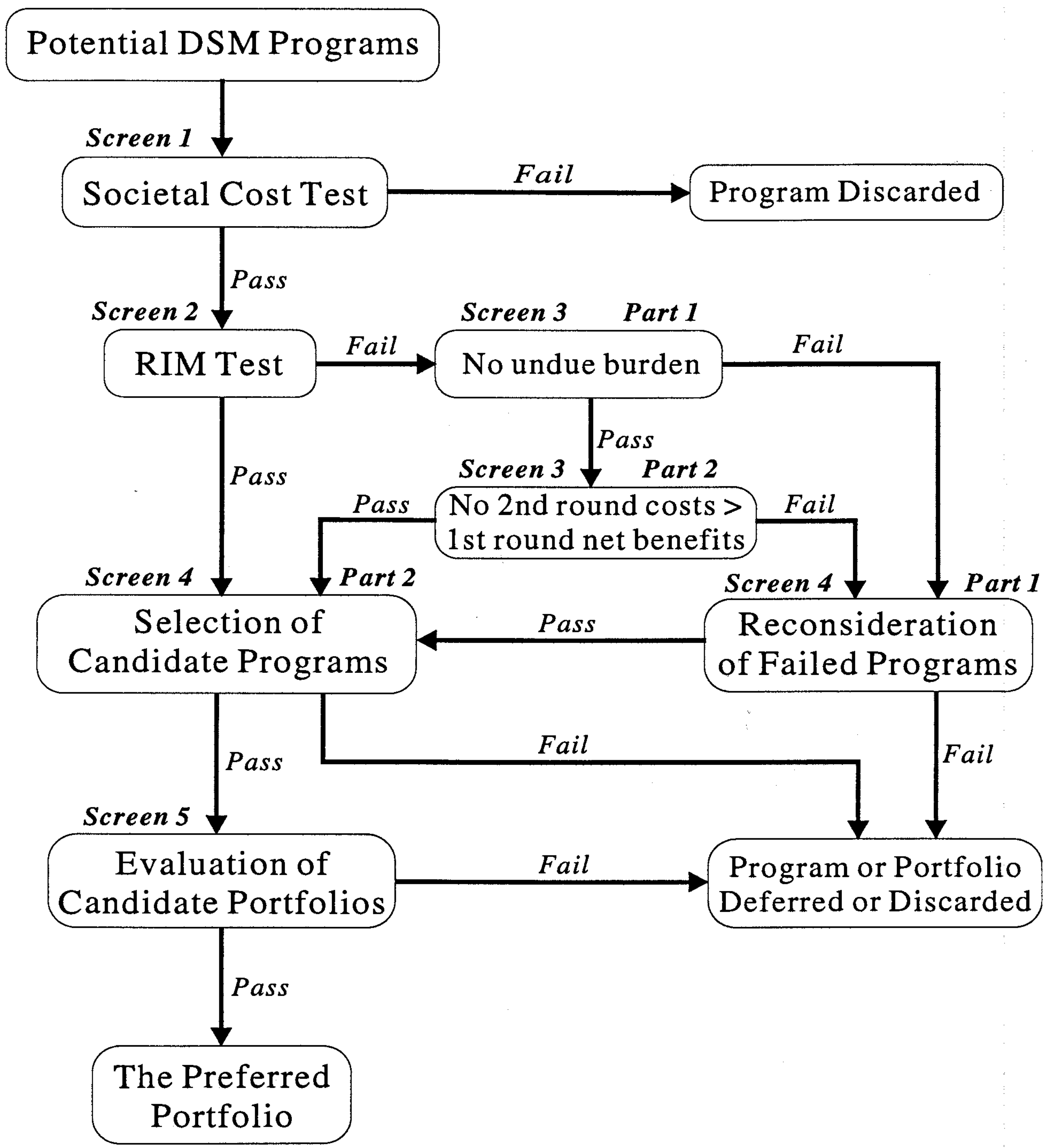
4.1.2 When developing a DSM portfolio, potential programs need to be identified for consideration. Some of the factors that should be considered in the selection of potential programs are: achievable potential; capture of potential lost opportunities; synergism among programs; and the breadth of the portfolio.

Program Screening

4.1.3 Once potential programs have been identified, screening is required to assure the development of a preferred DSM portfolio. In general, the Board endorses the Consensus Statement as constituting a reasonable approach for screening DSM programs. The screening process and steps that the Board expects the utilities to follow are summarized in Figure 1.

FIGURE 1

Recommended Screening Process for DSM Programs and Portfolios



4.1.4 Figure 1 conveys these steps in a linear fashion, but this is done only for illustrative purposes. The Board recognizes that the planning process may be non-linear and iterative. Consequently, the screening process should have sufficient flexibility to allow the utilities to return to earlier steps and to re-evaluate conclusions.

4.1.5 The Board considers that four major qualitative assessments should be incorporated in the screening process to avoid a mechanistic approach to the screening and to ensure that all appropriate considerations are included in the development of a DSM portfolio. The first qualitative assessment, which is discussed under Issue 3, provides an interim measure to complement Screen 1 until all significant externalities are monetized. The second assessment is incorporated in Screen 4, which selects programs from those that fail the third screen, and compares them to the other surviving programs. The third assessment occurs in Screen 5 when candidate portfolios are identified during the selection of a preferred portfolio. The fourth qualitative assessment is discussed under Issue 7 and deals with the evaluation of implementation strategies for the preferred DSM portfolio.

4.1.6 When carrying out the qualitative assessments, the Board expects the utilities to use an explicit evaluation process and to document the assumptions made as well as the process followed. To properly assess a DSM program, portfolio or plan, it is important to understand how the evaluations were carried out and how the conclusions were reached throughout the entire screening process.

The Societal Cost Test - Screen 1

4.1.7 The Board endorses the Consensus Statement that the Societal Cost Test be the first screen that all DSM programs must pass. The Board is of the view that the SCT provides a comprehensive approach to measuring the overall net benefit to society of a particular DSM program. The Board does not believe that it is reasonable for a utility to pursue a DSM program which does not have a net benefit to society.

4.1.8 The Board recognizes that the use of natural gas can contribute to environmental problems and that this cost is not fully captured in the price of natural gas. During the hearing, the Board was made aware of the negative impacts that natural gas combustion and leakage can have on communities, land and water, and upon the atmosphere through emissions of nitrogen oxides and volatile organic compounds. In particular, special attention was paid to the contribution of natural gas to the greenhouse effect. In the Board's opinion, it is appropriate to consider environmental costs. The Board believes that the SCT is an effective way of addressing these concerns.

4.1.9 In principle, the Board is supportive of initiatives that improve price signals to consumers, since imperfect price signals can lead to significant and unaccounted for societal costs or induce inappropriate actions. During the course of the hearing and argument, the Board was reminded of discussions at the Canadian federal level on emission taxes and tradeable emission permits, and the U.S. efforts through that country's Clean Air Act to use tradeable permits to control atmospheric pollution. The Board was also advised of the initiatives by the City of Toronto in cooperation with Consumers Gas and Ontario Hydro to reduce carbon dioxide ("CO_2") emissions by 20 percent from 1988 to 2005. In addition, the Board was reminded of the cautioning by the Government of Ontario regarding the negative impact that the internalization of societal costs via taxes could have on the competitiveness of Ontario industry.

4.1.10 The Board believes that initiatives to take account of natural gas externalities through energy prices and through planning approaches, such as the SCT, are complementary since it is unlikely that all externalities will ever be included in energy prices.

4.1.11 While using a strict SCT as the principal standard may be a laudable goal when determining whether a DSM program should be implemented, the Board believes that it is not currently possible to adopt this approach. Since the monetization of externalities as they relate to the gas utilities in Ontario is in its infancy, the full effect of internalizing these externalities cannot yet be assessed. In the interim, the Board concurs with the more cautious approach presented in the Consensus Statement which proposes the use of the SCT as the first screening test for a DSM program.

4.1.12 The Board notes that the Consensus Statement defines the SCT as including all costs and benefits. The Board has concerns that this could result in an infinite search. Accordingly, the Board expects the utilities to interpret this definition in a reasonable manner for both market-determined and monetized costs and benefits.

The Rate Impact Measure Test - Screen 2

4.1.13 The Board concurs with the Consensus Statement on the use of the Rate Impact Measure test as the second screen. The Board is of the view that the RIM test is an appropriate second screen because programs which pass this test will have a net societal benefit, without requiring cross-subsidization or causing any net rate impact, and therefore, should be considered further. However, the Board believes that it may not be prudent to implement only DSM programs that meet this second screen. Valid objectives (such as the avoidance of lost opportunities, the optimization of potential societal benefits, the improvement of safety and system reliability, and the need to broaden the DSM portfolio) may require the further consideration of some programs.

Consideration of Undue Burden & Second Round Impacts - Screen 3

4.1.14 The Board endorses the third screen described in the Consensus Statement. This screen requires that any increase in rates, resulting from programs that pass the SCT but fail the RIM test, not impose an undue burden on an individual or class of customers. Rate increases need to be considered both in the short and long term and assessed to ensure that they do not cause second round net societal costs that are expected to exceed the first round net societal benefits. These requirements are incorporated as Parts 1 and 2 of Screen 3.

4.1.15 The Board believes Part 2 of the third screen to be essential to ensure that DSM programs will not lead to customers switching from natural gas to less environmentally desirable fuels or reduce conversions and attachments to natural gas. The Board is aware that "dual-fuelled" gas customers are very price-sensitive and this must be taken into account. While it may be difficult to calculate the second round costs, the Board expects that utilities will undertake all reasonable efforts to do so. This would help to avoid the replacement of natural gas in applications for which the use of gas is preferable from a societal standpoint.

4.1.16 As part of the information requirements for carrying out the third screen, the Board expects the utilities to calculate the net societal benefit per dollar of subsidy for each program. This will provide further insight into the relative merits of individual DSM programs.

Final Program Screen - Screen 4

4.1.17 In addition to the three screens described in the Consensus Statement, the Board has added a fourth screen, which requires a qualitative assessment of those programs that have failed the third screen, as well as an overall evaluation of all of the surviving programs.

4.1.18 Part one of Screen 4 refines the screening process by permitting factors not covered in the initial three screens to be included in the selection of programs which have failed the third screen. These additional factors may include the magnitude and importance of avoided lost opportunities, the size of the net benefits associated with the implementation of the program, the improvement of safety and system reliability, and the contribution of the program to the breadth of the portfolio. Each program should be assessed from a pragmatic point of view regarding the likelihood of its acceptance and success, since even the most economically attractive DSM program can be useless unless customer acceptance is forthcoming.

4.1.19 Part 2 of Screen 4 involves the assessment of each program which has passed Screens 2, 3, or 4, to determine the program's suitability as a candidate for further consideration in comparison to the other surviving programs.

Identification of Candidate Portfolios - Screen 5

4.1.20 Candidate programs, once identified, should then be combined into candidate DSM portfolios. The candidate portfolios should be derived by examining the relative importance of the DSM plan objectives as well as the degree to which these objectives are met by the portfolio.

4.1.21 The final portfolio should result from an evaluation leading to the selection and combination of the preferred programs from each portfolio, or the selection of a preferred portfolio from among the candidate portfolios developed.

Customer Contributions

4.1.22 Since ratepayers who participate in DSM programs share in the direct as well as the broad societal benefits of these programs, the Board considers it appropriate that these ratepayers share in the costs of achieving these benefits. However, when considering the level of DSM contribution to be obtained from a customer class, the utilities are cautioned to be sensitive lest they impose hardships on low-income ratepayers or encourage industrial gas users to switch to less environmentally desirable fuels.

Accordingly, the Board endorses the provision in the Consensus Statement that: "Customer contributions are appropriate to the extent that they do not seriously reduce overall participation or foreclose the participation of specific customer groups". The Board also notes that customer contributions will reduce or eliminate the need for cross-subsidies.

4.1.23 The Board supports the provision in the Consensus Statement that the Participant Test is one factor to be considered in establishing appropriate levels of contribution, since this test provides an assessment of the direct costs and benefits to be accrued to those who participate in the DSM program.

4.1.24 The Board expects that the utilities will assess the required level of customer contribution on a case-by-case basis.

Rate Impacts of DSM Programs and the DSM Portfolio

4.1.25 The Board believes that rate impacts from DSM programs must be treated in a consistent manner with rate impacts from supply-side programs, since the costs and benefits of both types of programs can affect all gas customers. For example, supply-side programs may provide service benefits to all customers and may also provide specific benefits to certain customers in the vicinity of the new service. While most DSM programs are targeted to specific customer groups to realize certain benefits (although some information DSM programs may deal with all customers), these programs may also result in avoided system costs for all gas customers. Therefore, rate impacts caused by either demand-side or supply-side programs should be treated in an equivalent manner.

4.1.26 The Board recognizes that a portfolio of DSM programs may result in a rate increase. The Board will decide on the magnitude of any allowable rate impact on a case-by-case basis in rates cases.

4.1.27 The Board also recognizes the important role that the energy conservation programs of the gas utilities play in achieving the Government of Ontario's energy and environmental policy goals. In a letter to the Ontario Energy Board dated 28 February 1992, the then Deputy Minister stated that:

> Energy efficiency has been identified as the Government's top priority in the energy sector ...[and] as a key to achieving the Government's objectives of economic competitiveness, environmental protection, energy supply security and sound energy planning ... Natural gas utilities, in conjunction with other energy supply service companies within the province, are also expected to be central players in achieving these objectives through the delivery of energy efficient services and programs.

4.1.28 The Board concurs with these policy goals and, as a result, believes that a rate impact may be reasonable if DSM programs that survive the screening process can lead to gains in energy efficiency and environmental protection.

4.1.29 The Board also heard evidence that carbon dioxide and methane emissions due to the use of natural gas contribute to strengthening the greenhouse effect and, although there is scientific uncertainty regarding the amount and rates of warming and the resultant impacts, increased concentrations of greenhouse gases will lead to a warmer climate. The Board takes notice of a Discussion Paper prepared for Environment Ontario's Consultation on Global Warming, dated September, 1992. In this Discussion Paper, the Ministry of Environment and Energy adopted, as a starting point, a "no regrets" approach to global warming which provides insurance against potentially catastrophic outcomes by taking actions that make sense whether the warming predictions are right or not. Allowing a reasonable rate impact in order to support DSM initiatives which lead to significant reductions in the production of greenhouse gases is appropriate under a "no regrets" approach.

4.1.30 When considering a rate impact, the Board believes that the level of the impact should be based on questions such as:

- Will the immediate impact on customer bills be excessive?
- Is it likely that customer bills will, in the longer term, be unaffected or reduced even if rates increase?
- Will the impact on certain groups, such as low-income customers, be onerous?
- To what degree will the various stakeholders share in the benefits of a particular DSM program?
- Will improvements in the security or overall cost of operating the utility system create benefits beyond the first round impacts of the DSM program?
- Will the long-term net societal benefits of the DSM program override its immediate rate impacts?
- Are the net societal benefits of such magnitude and importance as to give priority to their attainment?
- Do opportunity costs demand prompt action?
- Will an important DSM program be left undone, or poorly done, if a ratepayer subsidy is not provided?
- Will the inclusion of the DSM program contribute to a broader menu of programs and thereby recognize the needs and perspectives of groups, such as low-income customers, Aboriginals and farmers, that might otherwise be precluded from participating?
- Will the inclusion of the DSM program take advantage of synergies among programs?

4.1.31 The Board expects the utilities to work toward developing strong, broad-based, self-sustaining DSM programs which continue to improve the level of energy efficiency. Thus, the Board also expects the utilities to be vigilant in their program design, and limit the level of rate impact, in order to minimize the need for cross-subsidization.

Using Existing Delivery Mechanisms for DSM Programs

4.1.32 When developing a portfolio of DSM programs, the Board expects the utilities to include successful non-subsidized approaches such as those used by the ESCOs. The ESCO approach for industrial, institutional, and large commercial clients is performance-based, contains measures with short, medium and relatively long payback periods, and often requires the client to accept the current level of utility bills until the DSM costs are fully recovered. The ESCOs also typically accept the risk that a program may not achieve its forecast savings.

4.1.33 The Board believes that it would likely be unproductive for the utilities to compete with or replace the effective DSM delivery mechanisms that are currently available from ESCOs or local providers of energy products or services. The Board feels that the use of these mechanisms is likely to be more cost-effective and efficient than the utilities developing their own. However, certain situations may require the utility to take a more aggressive role. The Board expects that the utility will justify, during its rates case, whatever approaches it uses for the delivery of DSM programs.

4.1.34 The Board also considers it preferable for a utility to design energy conservation programs which include all relevant energy forms, rather than just focusing on natural gas conservation measures in isolation. This more efficient, cost-effective and environmentally sound approach will require cooperation with other organizations such as Ontario Hydro and municipal electric utilities. The Board encourages such cooperation.

E.B.O. 134

4.1.35 With regard to the methodologies described in E.B.O. 134, the Board finds that the evidence provided at this hearing is insufficient to make a determination on what, if any, modifications are necessary. However, the Board recognizes the importance of having consistent treatment of supply-side and demand-side programs and the need to ultimately integrate the two types of programs. The integration phase and the next steps required in the IRP process, including the question of modifications to the E.B.O. 134 methodology, are discussed under Issue 10.

5. ISSUE 3 TREATMENT OF EXTERNALITIES - MEASUREMENT AND MONETIZATION

5.0.1 The distribution and use of natural gas have cost consequences for society which are not routinely accounted for in a utility's cost of doing business. Effective DSM programs should reduce these external costs. For example, improved efficiencies in the use of energy will reduce the emissions of combustion products. Given this potential for societal benefits, the Board has addressed the issue of how externalities should be factored into the analysis of DSM programs. The inclusion of externalities is an important issue because there could be substantial impacts on the costs and benefits of a specific DSM program, depending on how externalities are internalized.

5.0.2 This issue was included in the Demand-Side Issues List as:

> ***Should societal and/or environmental externalities be included in the cost analysis of demand side management ("DSM") programs? If so, how should these costs and benefits be included?***

5.0.3 In response to these questions, Board Staff, CAESCO, Centra, CEG, CAC(O), Consumers Gas, Pollution Probe, and Union agreed to the following Preamble and Consensus Statement. The City of Toronto agreed to the Consensus Statement only.

Preamble

All externalities (environmental and social) should be included in the societal cost-effectiveness test. However there are practical limitations on our current ability to identify, measure and monetize externalities.

There should be a distinction made when dealing with environmental externalities between the quantities of material emitted, the effects on the environment and the monetary values attached to them. All environmental externalities need to be measured first and then monetized. In some cases the first step is well understood and in others there has been progress in establishing a monetary value. Having both a measurement and a monetized value for environmental externalities requires further work.

The first step in this process will be to measure and monetize atmospheric emissions from fossil fuel use as impacted by DSM programs. The working group described below will be charged with this task along with evaluation of other externalities.

It should be noted that monetization of externalities will reflect considerable judgement and there may continue to be uncertainty with respect to the relative value of monetized externalities when considered in the same context as other economic factors.

The approach to measuring and monetizing externalities must be consistent with government policy and mindful of the ongoing debate in different jurisdictions.

Consensus Statement

1) All measured and monetized societal and environmental externalities should be individually accounted for in the Societal Cost Test once it *is possible to measure the externalities based on scientifically defensible data.*

2) *There is merit in conducting sensitivity analysis for monetized values of externalities in order to reflect the variance in potential impacts that they might have on society.*

3) *Those societal and environmental externalities which can be identified, measured but not monetized at this time should be given qualitative consideration by the utilities and the Board in their review of DSM programs during cost effectiveness testing.*

4) *The three utilities should adopt a consistent approach to the identification and measurement and valuation of societal and environmental externalities.*

Positions of the Parties

5.0.4 Board Staff submitted that the Consensus Statement provides the utilities with sufficient direction on the treatment of externalities, and that the monetization of all or even many externalities may not be necessary before the utilities can ensure that a particular program passes the SCT.

5.0.5 Board Staff stated that it supports DSM programs as a tool for reducing externalities such as greenhouse gas emissions. It supported the Consensus Statement because it recognizes such externalities on an equal footing with other costs and benefits when evaluating cost-effectiveness.

5.0.6 CEG submitted that the purpose of an externality valuation is to cause the customers who are currently enjoying the energy service benefits to gradually take responsibility for the costs of reducing the externalities they impose on others. It argued that monetized externalities should be valued equally with financial costs. If environmental impacts are certain to be created, but the amounts are uncertain, CEG stated that zero is clearly the wrong value to assign to those impacts. Externality estimates need not be perfect or completely accurate to be considered "scientifically defensible" and useful in energy planning.

5.0.7 In CEG's submission, including externality costs in the gas system planning process does not require the Board to become expert on all environmental issues in order to value impacts appropriately. Adoption of the Cost-of-Control approach leaves these decisions to the environmental regulators. Any reductions in pollutants which are achieved by a DSM activity are then valued at the cost of controlling them by an alternative method.

5.0.8 CEG further argued that the Board should not delay accepting the Cost-of-Control approach for natural gas in order to wait until this methodology is more broadly applied. The Board should take a leadership role, since monetization of externalities in the gas sector will surely speed the application of the Cost-of-Control approach to other fuels.

5.0.9 Energy Probe took the position that, since there is no market for externalities, the accuracy of monetized externality values cannot be tested and, therefore, cannot be considered reliable. Energy Probe stated that because externality cost estimates are highly uncertain, they should be given less weight than financial costs which are more certain. Moreover, in its view, the Cost-of-Control approach would be difficult to apply to CO_2 emissions which are not yet subject to government regulation.

5.0.10 A second problem Energy Probe identified arises from trying to internalize only the cost of externalities for natural gas while ignoring the environmental impacts that result from the use of competing fuels. It would not be in the best interest of the environment to subsidize DSM programs that will increase natural gas rates. In support of its argument, Energy Probe quoted its witness, Dr. Ruff, who testified that: "...even if the price of gas is too low because it does not include all the environmental impacts of gas production and use, it might be that the gas price should be decreased even more ... if other, dirtier energy forms cannot be priced to reflect their external environmental costs."

5.0.11 Consequently, Energy Probe recommended that the Board not try to internalize externalities for natural gas at all until equal regulatory treatment of less desirable fuel forms is assured. Energy Probe advised the Board to recommend that the federal government establish economically efficient, polluter-pay regulations, such as emission charges or tradeable pollution permits, which incorporate the costs of externalities in the price of all fuel forms. If the federal government fails to act quickly, according to Energy Probe, these regulations should be implemented by the Ontario government.

5.0.12 The City of Kitchener supported the Consensus Statement with one exception. It would exclude those externality benefits that fall outside the ambit of the utilities' mandate or responsibilities.

5.0.13 Although OMAA agreed with the intent of the Consensus Statement, it was not a party to the consensus. OMAA's position was that all relevant external costs associated with the production, transportation and consumption of natural gas should be taken into account. OMAA expressed concern that social and some environmental externalities will be given little weight in practice, unless there is a significant commitment of resources to effectively evaluate the full range of externalities. OMAA was concerned that giving less weight to monetized externalities than financial costs in the SCT could reduce the impact of the externalities on the planning process.

5.0.14 OMAA stressed that the identification and valuation of externalities must be comprehensive and accurate. Of particular concern is the issue of those externalities which are difficult to quantify and monetize. In such instances, the qualitative treatment in the planning process must be meaningful. OMAA submitted that its members should be consulted on this matter, since they offer a unique expertise that can assist in this process. OMAA also argued that justification should be provided for those externalities which are not monetized.

5.0.15 Union submitted that, in order to take account of social and environmental externalities, both the costs and benefits of supply-side and demand-side options must be considered and given appropriate weight. It noted the difficulties involved in trying to monetize externalities, and urged that judgment be exercised when attempting to compare the value of monetized externalities with economic costs determined by market transactions.

5.0.16 In Union's view, monetized externality values should not be treated in an equivalent manner with financial costs, since this could lead to adoption of a DSM program which causes a rate increase that would not have occurred had a less costly (in terms of real dollars) supply-side option been chosen.

5.0.17 Union pointed out that care must be taken to avoid the monetization of externalities in a way that makes gas appear less attractive than more environmentally detrimental fuels. In its submission, the environmental and other benefits resulting from the wise use of gas are far greater than the benefits associated with attempting to reduce the use of gas.

5.1 BOARD FINDINGS

5.1.1 In general, the Board views the Consensus Statement as a reasonable approach to the inclusion of externalities in the Societal Cost Test. However, the Board finds it appropriate to make refinements to the Consensus Statement to improve its effectiveness and ease of implementation.

5.1.2 The Board concurs with the Consensus Statement that, when dealing with environmental externalities, a distinction should be made between measuring and monetizing an externality. The Board believes that this explicit distinction is necessary to ensure that the monetized value is quantified appropriately. The derivation of the externality value should be documented properly so that it can be readily understood by the Board and other interested parties.

5.1.3 The Board notes that the preamble to the Consensus Statement focuses on the use of this distinction for atmospheric emissions. However, the Board expects that the distinction will be applied to the treatment of other environmental externalities and to social externalities.

5.1.4 In the Board's view, the first step when considering the measurement of any externality is to determine the significance of the externality in a qualitative manner. If the utility finds the externality to be significant, then the utility is expected to attempt to measure its effect (e.g. quantity of material emitted, change in water or air quality). Once the effect of the externality is measured, the next step should be the measurement of its impact (e.g. the damage to plant, animal and human health, the level of improvement in habitat or biodiversity). When it is not possible to measure the effect with sufficient precision for monetization, the externality should be incorporated into the qualitative component of the SCT.

5.1.5 The Board concurs with the Consensus Statement that all monetized externalities should be derived from scientifically defensible data, i.e. data that are valid and reliable. The Board also believes that, in order to apply the SCT properly as a planning tool, the dollar values of monetized externalities must be weighted equally with market-determined costs.

5.1.6 However, the Board is concerned that the SCT may be applied in an overly restrictive manner, and reminds the utilities that this test is only the first screen for the inclusion of a program into the DSM portfolio. When the utilities are deciding to include an externality in the SCT, the Board expects them to determine whether its inclusion is warranted after considering the trade-off between the limited quality of the data on which the externality is based and the benefit of including its avoided costs in the SCT. Ultimately, the question of whether or not an externality is included in the SCT must be defensible at a rates case.

5.1.7 The Board accepts that the monetization of externalities for natural gas utilities is a new field of endeavour with little direct or relevant experience in other jurisdictions, and this creates uncertainty. Accordingly, the Board concurs with the Consensus Statement that considerable judgement may be required. To address this uncertainty, the Board expects the utilities to conduct a sensitivity analysis for each monetized value for the SCT. However, as the utilities gain experience with monetization, the Board feels that the level of uncertainty, and therefore the need for the sensitivity analyses, will decline.

5.1.8 The Board is concerned about the qualitative assessment recommended in the Consensus Statement. It involves using two approaches to assess externalities which are not compatible, since the results cannot be directly summed to produce an overall net societal benefit. Moreover, the Consensus Statement does not provide direction on how to calculate an overall net societal benefit based on the two approaches. The Board prefers an approach to qualitative assessment which includes all of the significant costs and benefits of a DSM program and produces a non-monetary conclusion for the overall net societal benefit.

5.1.9 When the utilities are monetizing externalities, the Board prefers that, at this time, they use the Cost-of-Control method for calculating avoided costs. This method relies on an indirect valuation of damages based on the cost of compliance with existing regulations. It was endorsed by a number of parties during the hearing. The Board is of the view that this evaluation technique provides a relatively direct approach to monetization.

5.1.10 The Board notes that the Cost-of-Control method works best for regulated substances, but that it can be used for unregulated substances such as carbon dioxide by assuming a target of control and estimating the cost of compliance with that target. The Board believes that targets for emission control are most appropriately set by government and urges that this be done as soon as possible. However, the Board is prepared to accept assumed targets for DSM planning purposes in the absence of government regulation.

5.1.11 The Board views the use of the Cost-of-Control method as an interim measure until Damage Costing can be done in a straightforward and cost-effective manner. Damage Costing, which involves the calculation of the actual damage costs to society in dollar terms, is considered by the Board to provide a more accurate assessment of impacts. However, at present this evaluation method is extremely complex and costly to implement. The Board expects the utilities to keep apprised of developments on Damage Costing in other jurisdictions, and to keep the Board informed of any such developments at rates cases. A cooperative approach among the utilities on these activities would help to minimize costs.

6. ISSUE 3 TREATMENT OF EXTERNALITIES - CONSULTATION

6.0.1 As part of the discussion on externalities, the issues were raised as to whether the utilities should employ a consultative process when determining how externalities should be accounted for in their DSM plans, and how such consultation should be achieved. One proposed alternative was to form a working group to ensure that the affected parties have an early opportunity to contribute to the development of DSM plans.

6.0.2 Among the matters proposed to be considered by a working group were: which externalities should be included when defining avoided costs; what values should be ascribed to these externalities; and whether participation in the group should be funded, and if so, how should it be done.

6.0.3 Board Staff, CAESCO, Centra, CEG, CAC(O), Consumers Gas, Pollution Probe, the City of Toronto and Union agreed to the following proposal in the Consensus Statement on Issue 3.

Working Group Proposal

A working group with representation from each of the utilities and other interested parties involved with DSM should report to the Board on a recommended methodology for treatment of those externalities to be *included in the LDCs' respective Societal Cost Test. If possible the Working Group will be convened prior to the DSM hearing. Its mandate will be to achieve consensus on the methodology for identification, measurement and monetization of externalities and the values themselves where possible. The anticipated result will be to establish a common basis for the LDCs to include monetized externalities as part of the DSM program evaluation.*

The Working Group will present its recommendations to the Board and report its conclusions to the E.B.O. 169-II interested parties.

Positions of the Parties

6.0.4 Board Staff argued that the proposed working group provides a means of ensuring that the monetization of externalities is done in a consistent manner for the three utilities, with input from interested parties. Board Staff submitted that the Board should recommend how the utilities should evaluate those externalities that cannot be monetized. The Board should also establish a time frame, such as six months, within which the working group should report its findings to the Board.

6.0.5 Board Staff concluded that funding would be required in order for interested parties to participate effectively in the working group. It submitted that early participation by interested parties is essential in order to develop broad support for the monetized values in future proceedings. Although Board Staff recognized that a larger group is potentially more unwieldy, it argued that there should be no discrimination against groups that may not have been active in the proceedings thus far.

6.0.6 CAESCO agreed that monetization of externalities should be researched through the working group. CAESCO noted that ESCO programs achieve their load-saving goals and reduce environmental externalities without the need for utilities to internalize any externality costs. This added benefit should be factored into the utilities' DSM plans.

6.0.7 Centra suggested that the working group is more likely to succeed if it develops, by agreement, its own specific objectives, work plan and timetable. These should be filed with the Board, with an initial report to be delivered within six months of the Board's decision in Phase III. Discussions within an ad hoc working group initiated by Centra indicated that the work plan would probably include: the identification of externalities that should be considered in an IRP context; a survey of approaches used in other jurisdictions; a review of relevant existing studies; a determination of the preferred approaches to quantifying and monetizing externalities; and a report of the working group's recommendations to the Board and the parties to E.B.O. 169.

6.0.8 Centra proposed that membership in the working group be open to any party from the E.B.O. 169 proceedings, as well as to any other appropriate interested party agreed to by the working group. Representation from the Ontario Ministry of Environment and Energy should also be sought to ensure the working group is kept apprised of relevant Ontario government policy and on-going studies of particular relevance. Centra supported funding of per diem and travel expenses, and suggested that "the group as a whole should determine the extent to which expert assistance is required and should jointly sponsor such assistance".

6.0.9 CEG stated that, while it prefers an informal approach, it is amenable to the working group being structured by the Board. CEG recommended that public interest group participation in the working group be funded. It suggested that, in the absence of legislative change, it would be appropriate to use the Board's Cost Award Guidelines when funding such participation. CEG recommended that the Board establish a reporting deadline, such as the six-month time frame suggested by several parties.

6.0.10 CAC(O) suggested that the Board should issue specific guidelines to the working group, directing it to provide: the best current control costs for emissions (other than carbon dioxide) arising from the use of natural gas; a survey of the monetary values which have been proposed elsewhere for the environmental effects of carbon dioxide emissions; a survey of the levels of carbon tax which have been proposed in other jurisdictions; and, an analysis of the reasons behind the wide range of values on these items.

6.0.11 Consumers Gas expressed the opinion that the working group's results would be produced most quickly and cost-effectively if an informal, consultative approach were employed. Consumers Gas indicated that it is prepared to fund the working group, provided the Board accepts these costs as eligible for consideration as a cost of service.

6.0.12 In Consumers Gas' view, original research or the extensive involvement of external experts would not be necessary or desirable. If external assistance is required, Consumers Gas agreed with Centra and Union that the working group should collectively engage consultants who would work on behalf of, and report to, the group as a whole. Consumers Gas also proposed that the Board direct the three utilities to submit a draft budget to the Board on behalf of the working group, after consultation with the other working group members.

6.0.13 Consumers Gas urged the Board to direct the working group to produce a status report within six months outlining recommendations for the Board to consider and a timetable for further work or reports.

6.0.14 The City of Kitchener encouraged the Board to recognize the working group's role in compiling and organizing the literature on monetization and determining the range of monetized values as evidenced by the literature. However, it argued that the Board should not expect the working group to reach a consensus on monetized values, and that task should be excluded from the working group's mandate. Moreover, the working group should not supplant the management decision-making role of the LDCs under regulation.

6.0.15 The City of Kitchener also submitted that the working group's membership should be broad, but should also avoid duplication in the representation of the environmental groups, customers and native peoples. These three distinct interest groups should each be obliged to select a single representative party to minimize costs and enhance consensus-building while encompassing all views without prejudice.

6.0.16 OMAA saw the working group as useful and supported such aspects as government representation, a six-month time frame, and a clear mandate. OMAA recommended that the mandate of the working group should be broadened to include the development of a methodology for the qualitative treatment of non-monetized externalities. It also recommended that the working group present its consensus and non-consensus positions at a separate oral hearing before the Board.

6.0.17 OMAA stressed that the identification and valuation of externalities must be accurate, particularly for those externalities which are difficult to quantify and monetize. In such instances, the qualitative treatment in the planning process must be meaningful. OMAA submitted that its members should be consulted on this matter, since they offer a unique expertise which can assist in the process.

6.0.18 Union recommended that the working group be limited to participants in the E.B.O. 169 hearing, with the addition of a government representative if desired. The group should be given a specific mandate to prepare a timely report indicating the extent to which the parties agree on the externalities to be considered, their measurable impacts, monetized values and the methodologies to be employed. The working group should also report on the extent of consensus within the group, but it should not be expected to negotiate a consensus if one does not exist after the survey, assessment and discussion of methodology are completed. Union also recommended that any consultants be retained by the group as a whole and be paid for by the three LDCs. Union agreed with the City of Kitchener that the mandate of the working group should not include the monetization of externalities.

6.1 BOARD FINDINGS

6.1.1 The Board concurs with the Consensus Statement that the three utilities should adopt a consistent approach to the identification, measurement, and valuation of externalities. This approach should foster cooperation among the utilities to develop a sound approach and should reduce the complexity of the regulatory process.

6.1.2 To develop a consistent approach, the Board expects the utilities to form a joint collaborative on externalities, and the review of qualitative assessment methodologies employed in other jurisdictions in order to recommend approaches to be used in the DSM planning process in Ontario ("the Collaborative"). The purposes of the Collaborative include those of the working group identified in the Consensus Statement.

6.1.3 When the utilities are forming the Collaborative, the Board expects them to seek representation which incorporates diverse perspectives (e.g. residential, commercial and industrial customers, special interest groups such as environmental and Aboriginal groups, and local and provincial government representatives) in a balanced, manageable and non-duplicative manner. Since the Collaborative is not a continuation of the E.B.O. 169-III proceeding, the utilities are not automatically bound or limited to the parties in these proceedings when selecting participants for the Collaborative.

6.1.4 To ensure the effective participation by diverse groups, the Board expects the utilities to provide funding in a manner consistent with the Board's

Cost Award Guidelines, but to consider the provision of financial compensation, possibly in the form of honoraria, which respect the value of the time being spent by employees and officers of the participants. When the services of experts are required, they should be retained on behalf of the group as a whole, rather than underwriting the costs of a number of experts representing the individual participants. The Board also suggests that the utilities consider the use of an independent facilitator to ensure the smooth functioning of the Collaborative. The reasonableness and prudence of the expenditures incurred by each utility will be tested at the rates hearing as a cost of service issue.

6.1.5 The Board is concerned that having the Collaborative focus initially on atmospheric emissions is too limited. It may lead to a lack of emphasis on other externalities and to insufficient attention being applied to the development of an appropriate approach to the qualitative assessments required in Screens 1, 4 and 5 (refer to Issue 2).

6.1.6 The Board expects the mandate of the Collaborative to include the preparation of a report that:

- identifies the range of Cost-of-Control costs being used in the SCT in other jurisdictions for air emissions as well as other environmental and social effects; explains the variance in the values used; and makes recommendations, where possible, on the most appropriate costs to be used in Ontario;

- carries out a survey of how non-regulated emissions and other effects from natural gas use (e.g. CO_2 emissions and effects on communities) currently are treated in the SCT in other jurisdictions, as well as proposals for their treatment in the future; explains the rationale for the approaches taken; and makes recommendations, where possible, on the most appropriate approach for Ontario, including the values to be assigned to the emissions and other effects;

- identifies other externalities which are not included in the SCT in other jurisdictions, but which should be included in Ontario; provides the rationale for the inclusion of other externalities; and makes recommendations, where possible, on the most appropriate approach for their treatment, including the values which should be assigned to them;

- reviews and assesses methods employed in Ontario and in other jurisdictions which can be used for the qualitative assessments required in Screens 1, 4, 5, and in the evaluation of portfolio implementation strategies; and makes recommendations, where possible, on acceptable approaches;

- identifies if and where there is a need to consider the unique characteristics of each utility; and

- describes and assesses the process of consultation that was used for the Collaborative.

6.1.7 The Board expects the members of the Collaborative to reach an agreement on the terms of reference, the timetable, budget, funding and work plan for the Collaborative and to report to the Board and the parties on these initial matters by September 30, 1993. Once the work of the Collaborative has been completed and the Board has received the final report of the Collaborative, the Board will determine how to proceed further. The Board encourages the Collaborative to strive to submit its final report to the Board and the parties by February 28, 1994 in order that the results can be incorporated in the examination of DSM plans for the fiscal 1995 test years of the LDCs.

6.1.8 In the event that the above deadlines are found to be unrealistic, the Board expects the utilities to make this known to the Board as soon as possible and, when doing so, to define the causes of delay and to jointly commit to a revised timetable.

6.1.9 The Board's endorsement of the consultative process is not limited to the issue of externalities. While there is an urgent need to apply a consultative effort to matters relating to externalities and qualitative assessment methodologies, the potential advantages of consultation on DSM matters extend beyond these issues.

6.1.10 The Board believes that formal ongoing consultation, of the type embodied in the Collaborative on externalities, could be an effective approach to addressing a number of DSM issues which are yet to be fully resolved. However, to be effective, other consultative groups will likely need to be formed to focus on specific issues, rather than creating an institutionalized, general forum.

7. ISSUE 4 REGULATORY TREATMENT OF DSM INVESTMENTS - COST RECOVERY

7.0.1 The regulatory and accounting treatment of DSM investments is a critical component of IRP. Of specific concern is the question of whether the costs and the accounting treatment of demand-side investments should be treated consistently with those of supply-side investments.

7.0.2 This issue was included in the Demand-Side Issues List as:

> ***How should investments in demand side options be treated for rate-making purposes? Are the cost recovery mechanisms for demand side options consistent with the accounting treatment of other utility expenditures?***

7.0.3 In response to these questions, Board Staff, CAESCO, Centra, CEG, CAC(O), Consumers Gas, OMAA, Pollution Probe and Union agreed to the following Consensus Statement on the ratemaking treatment of DSM investment. Energy Probe agreed with the opening paragraph, point 4 and the last paragraph of the Consensus Statement on this issue.

Consensus Statement

Given the basic assumption that DSM programs are desirable and should be undertaken by utilities, then there is consensus among the parties listed below that the matching of costs and benefits of DSM programs is appropriate. There is also agreement that investment in demand-side options should be treated consistently with investment in supply-side options. In general, accounting treatment should be in accordance with GAAP.

1) *DSM programs should be divided into capital investments and operating expenses.*

2) *Capital investments would be those expenditures with longer term benefits. The capital investment portion of the DSM program costs should be treated in a similar manner as traditional rate base components.*

3) *Expenditures with shorter term benefits (one year or less) should be expensed. The utility should be allowed to recover the operating expenses in the year in which they are incurred through the cost of service.*

4) *The amortization of capitalized expenditures should attempt to match the expected benefits of the investment, with amortization over the lifetime of the technologies or over the period of the benefits to be realized. This method of cost recovery is consistent with the accounting treatment of other utility expenditures. Where the energy savings are realized over an uncertain or extended timeframe (e.g. informational programs), or where the benefits to be realized are the avoided costs of future supply-side options, the costs should be recovered on a timely basis.*

5) *The utilities should establish a deferral or balancing account for DSM operating, and if necessary, capital expenditures. The deferral account would be used to accrue the difference between actual DSM expenditures and forecast expenditures. The disposition of the balance would occur in the next rate period. There would be a carrying cost associated with the deferral account.*

There is agreement that due to the uncertainties surrounding any initial DSM program, the utilities should establish a deferral or balancing account for DSM (operating and/or capitalized) expenditures. This would allow the utility the opportunity to recoup all of the costs incurred with respect to DSM program implementation, and would give the utility greater flexibility to respond to a program's success or failure.

If the utilities did not have such a balancing account in place, they might have a disincentive to go over budget and spend additional resources on a program, regardless of its success or penetration rate. Since DSM investments are non-traditional utility assets, they do not generate revenue, and therefore the utility would simply stop spending once it ran out of resources. Therefore the use of a balancing account ensures continued DSM program implementation and fewer lost opportunities. Any over- or under-spending would be reviewed by the Board during the rate case, and the Board would judge the prudency of the expenditures. The balancing account also has the additional advantage of lowering the utility's new risk with respect to investing in non-revenue generating assets.

There was agreement that this type of deferral account was particularly useful in the early phases of DSM implementation. Therefore, the parties agreed that the deferral account may not be necessary in later years when the utilities were more experienced with DSM programs and the expected results; it was agreed that the necessity of a deferral account should be revisited or reviewed periodically in the individual utility rate cases.

What kind of expenditures should be considered DSM investments?

Again, given the basic assumption that DSM programs are desirable and should be treated in a manner consistent with supply-side options, any DSM program costs that should be considered as investments (and therefore eligible for rate base treatment) are those that are long-lived in nature and that have long-lived benefits. The basic principle behind the capitalization and the amortization of DSM investments is to match benefits and costs to the greatest extent possible. Any accounting treatment of program expenditures included in rate base should also be consistent with GAAP.

Those expenditures to be considered investments should include: hardware costs owned by the utility (such as high-efficiency gas equipment); and customer incentive payments (rebates, low-interest loans).

Other expenditures that may be included in rate base may be programs with costs of a "one-time" nature. The examples given were labour costs with respect to DSM program development and implementation, or a portion of overhead and administration costs. The guiding principle would be consistent treatment of supply-side and demand-side costs. Any expenditures of an ongoing nature would more properly be expensed.

The amortization period of capitalized expenditures should match the useful life of the asset or DSM program benefit. With respect to informational programs (and other programs with uncertain, and hard to attribute, benefits over an undefined period of time), those costs might be more prudently recouped in a shorter time frame.

Positions of the Parties

7.0.4 Board Staff submitted that the three key factors to consider when assessing this issue are the consistent treatment of demand-side and supply-side options, the ease of application and regulatory review, and the matching of costs and benefits.

7.0.5 Board Staff contended that the utilities' concerns regarding the recovery of DSM costs were legitimate and that resource selection would be biased in favour of less risky investments. Accordingly, Board Staff recommended the use of deferral accounts for DSM operating and capital expenditures in order to reduce the risk associated with investments in non-revenue generating assets.

7.0.6 In the opinion of Board Staff, the use of deferral accounts would also improve the utilities' ability to respond to variances in program performance, and reduce the incentive to abandon programs once budgeted funds run out. Early abandonment could result in lost opportunities and confusing market signals. Board Staff suggested that the need for deferral accounts, and the prudence of the actual expenditures, would be tested during the rates case proceedings.

7.0.7 In response to CAESCO's suggestion that joint utility/ESCO programs should be included in the deferral account, Board Staff argued that this was inappropriate since such accounts were designed to protect the utility, and not a private enterprise, from the risk of not recovering costs.

7.0.8 Centra believed that DSM capital expenditures are likely to be larger than DSM operating expenditures. Consequently, capital investments should be included in a deferral account to ensure that DSM development will not be constrained unreasonably by cost considerations, and that utility and consumer interests will be balanced in the event that DSM programs are more successful than anticipated.

7.0.9 Centra submitted that its support for the use of a deferral account was not inconsistent with its opposition to decoupling, (as discussed under Issue 6). Centra agreed to the use of a deferral account, but it did not consider such accounts as a necessary prerequisite for the implementation of DSM. The use of a deferral account would not, in Centra's opinion, involve a major regulatory change, nor would it lead to all the other disadvantages of decoupling.

7.0.10 CAESCO recommended that joint utility/ESCO programs should be included in the deferral accounts with periodic rebates based on the achieved load savings. This would remove the DSM financial risk from the utility and permit it to earn a return on program funds.

7.0.11 Consumers Gas submitted that the proposed cost recovery mechanism would ensure the equal treatment of demand-side and supply-side options and facilitate the implementation of large scale, cost-effective DSM programs. Consumers Gas also agreed with Board Staff that the proposal would provide utilities with greater flexibility when responding to a program's success or failure.

7.0.12 Energy Probe argued that, in order to protect customers from possible rate impacts due to the implementation of financially unsustainable programs, DSM investments should be recovered from the proceeds of those investments, and not from an authorized regulated return. Accordingly, DSM should be a deregulated activity which is separate from the utility to protect customers from the adverse rate impacts caused by unsuccessful programs (see also Chapter 8). Energy Probe also contended that activities which are not profitable should not be allowed into rate base, and that the Board should disallow future DSM costs if the expected benefits do not materialize.

7.0.13 Energy Probe recommended that subsidies should not be considered as assets. If subsidized DSM is permitted, however, customer contributions should be included as a separate item on customers' bills.

7.0.14 While Energy Probe agreed with the principle of equal accounting treatment of demand-side and supply-side investments, it argued that such agreement should not be used to justify the equal treatment of unprofitable and profitable investments for the purposes of including them in rate base or recovering their costs.

7.0.15 Energy Probe further submitted that the Board should treat monopoly activities and naturally competitive activities differently. Since DSM activities are not a monopoly, they do not require regulation to protect the consumer or to allocate resources efficiently.

7.0.16 The City of Kitchener considered the accounting treatment proposed in the Consensus Statement to be a continuation of the current treatment of DSM and NGV activities, except for the introduction of the deferral account. In its view, the advantages of the deferral account had been established.

7.0.17 Union supported the establishment of DSM deferral accounts to provide equal treatment to demand-side and supply-side expenditures. For the same reason, Union argued that demand-side "investments" must be amortized and included in rate base. In its opinion, a deferral account was necessary in order to reduce regulatory and forecasting risks.

7.0.18 In reply to Energy Probe's submission that subsidies and unprofitable investments should not be allowed in rate base, Union argued that participant incentives were important for the success of Union's DSM programs, but that the cost of these incentives would be recovered from the programs.

7.0.19 Union argued further that the LDCs have been promoting conservation, and thus DSM, for a substantial period of time and, accordingly, there is no reason to disallow these activities now.

7.0.20 Union also disagreed with the position put forward by Energy Probe and Pollution Probe that the Board should maintain the ability to disallow future costs of a DSM program if the expected benefits do not materialize. Union argued that to disallow an investment, the Board would have to find that the utility acted imprudently at the time the investment was made, not retrospectively after the program is in place.

7.1 BOARD FINDINGS

7.1.1 The Board endorses the positions put forward in the Consensus Statement. It believes that, when considering DSM efforts, it is desirable to the degree possible to maintain a consistent relationship between the treatment of supply-side and demand-side costs.

7.1.2 The Board, therefore, also endorses the proposal in the Consensus Statement that the costs of long-term DSM programs (i.e. those with a duration of more than one year) be included in rate base and amortized over the estimated useful life of the programs. This would match benefits and costs in a manner consistent with the treatment of supply-side investments. The costs that should be eligible for consideration for inclusion in rate base include "hardware" costs; longer-term incentives, rebates and loan costs; and associated labour, overhead and administrative costs. The Board also supports the proposal that expenditures with shorter-term benefits (one year or less) should be expensed and considered for recovery through the cost of service in the year in which they are incurred.

7.1.3 The Board is cognizant that the success of new initiatives, such as DSM efforts, is critically dependent on the initial use of information, attitude development and "market" research efforts. The Board considers such efforts to be a necessary preamble for an effective DSM plan.

7.1.4 The Board recognizes that information and associated programs incur costs that are often difficult to associate with particular benefits, and may depend on variables that are difficult to forecast, such as the level and degree of customer acceptance. Thus, the Board feels it is appropriate to consider broad-based DSM information and associated programs as a separate category of expenditure.

7.1.5 The Board, therefore, believes that prudent, broad-based information and associated programs should be considered for recovery as legitimate cost of service items without requiring the identification of specified benefits that will be obtained. The Board believes that, because of the pervasive nature of generic programs, such as information programs, the benefits that will be generated will be difficult, if not impossible, to quantify. Such programs will, however, almost certainly have a beneficial impact. Thus, future rates case panels will likely be prepared to consider prudent expenditures on generic programs to be justifiable costs of service, even if specific quantified benefits cannot be ascribed to them.

7.1.6 Given the fact that these broad-based programs will have inter-franchise benefits, the Board expects that the utilities will coordinate and cooperate when undertaking such programs.

7.1.7 Notwithstanding the above, when information and marketing efforts are specific to a particular DSM program, they should be accounted for as a cost of that program, and justified on the basis of the program benefits that are to be achieved.

7.1.8 The Board is aware that there will be greater uncertainty over the accuracy of initial DSM forecasts due to the lack of experience in such matters. In order to avoid exposing the utilities to undue risk, while assuring that DSM is aggressively pursued, the Board endorses the use of deferral or balancing accounts as proposed in the Consensus Statement. The Board anticipates that as forecasting experience is gained the need for such accounts will diminish.

7.1.9 When balancing accounts are utilized, the amounts accruing should attract carrying charges. While it remains for the rates case panels to define how such carrying charges should be calculated, the Board suggests that carrying charges for capital investments should be based on the average of their monthly averages and should earn the allowed rate of return on rate base. The Board also suggests that expensed items should earn simple interest on the monthly opening balances at the utility's authorized cost of short-term debt.

7.1.10 Given the current frequency of rates cases, the Board expects that the amounts accruing in balancing accounts will be manageable and of only minimal inter-generational concern. Should the interval between rates cases be extended, interim measures to dispose of significant balancing account balances should be considered.

7.1.11 Each of the major LDCs has Natural Gas for Vehicles ("NGV") programs. The Board considers NGV programs to be outside the scope of DSM as currently defined. Due to the scale and self-standing nature of these programs, the Board requires that they be kept separate and not incorporated into the utilities' DSM portfolios.

8. **ISSUE 4 REGULATORY TREATMENT OF DSM INVESTMENTS - DSM AS A NON-REGULATED ACTIVITY**

8.0.1 Energy Probe proposed a model which would separate DSM activities from the regulated aspects of the utilities' operations.

Positions of the Parties

8.0.2 Energy Probe submitted that the business of supplying DSM products is not a natural monopoly, rather it is an inherently decentralized activity. It recommended a stand-alone, for-profit DSM business set up as a non-regulated activity. In its view, stand-alone, for-profit businesses have powerful internal incentives to successfully identify and implement conservation investments. In addition, the issue of what investments should be considered as DSM need not arise as a regulatory issue.

8.0.3 Energy Probe also submitted that the creation of a non-utility division for DSM will ensure that investments in demand-side options are recovered from the proceeds of those investments and will protect customers from possible rate impacts due to the implementation of financially unsustainable programs. Energy Probe recommended that the appropriate way to internalize externalities is through the price system by emissions taxes and tradeable emissions permits, rather than merely monetizing them for planning purposes.

8.0.4 Board Staff submitted that Energy Probe's proposal should be rejected. In its view, the proposal would greatly increase the regulatory burden, as the Board would have to examine the extent to which the utility's resources are devoted to non-regulatory activities.

8.0.5 Board Staff further submitted that Energy Probe's position on cross-subsidization is inconsistent. It noted that Energy Probe is vehemently against allowing cross-subsidies between groups of utility customers and users of gas, but has no qualms regarding cross-subsidies from one utility affiliate to another. Board Staff noted that the Board has traditionally allowed some degree of cross-subsidization among gas users. In Board Staff's view, equity concerns with respect to DSM would be addressed by a DSM portfolio containing a broad array of programs to be offered to all classes of customers.

8.0.6 Finally, Board Staff submitted that Energy Probe's position is partly based on the assumption that gas externalities are so small that it would be more costly for the Board to consider them explicitly than it would be to live with the effects. In the view of Board Staff, it is reasonable to believe that externality effects are probably large enough to warrant some market intervention. It submitted that since a major component of IRP is the consideration of externality values, there is a fundamental weakness in Energy Probe's position.

8.0.7 Consumers Gas submitted that the strict user-pay position taken by Energy Probe is not consistent with the realities of today's marketplace and, if adopted, it would result in unwarranted constraints on the scope and benefits of societally cost-effective DSM programs. According to Consumers Gas, adequate evidence has been brought before the Board to demonstrate the existence of significant market barriers to conservation, and to provide a rationale for a balanced portfolio of utility DSM programs.

8.0.8 OMAA submitted that it is difficult to reconcile Energy Probe's position on this issue with its other positions. In OMAA's opinion, it is unclear why the entrance of unregulated utility subsidiaries into the DSM marketplace would improve the functioning of that marketplace which, based on Energy Probe's evidence, is performing reasonably well.

8.0.9 Energy Probe replied that it agrees with the desirability of applying the same regulatory principles to the supply side and the demand side, but insisted that the important logical distinction between the natural monopoly activities and naturally competitive activities not be blurred as a result. It noted that gas distribution services are a natural monopoly which must be regulated to protect consumers, whereas DSM services are not a monopoly, natural or otherwise, and therefore do not require (or benefit from) regulation to protect the consumer.

8.0.10 Energy Probe submitted that the purpose of the regulation of DSM, according to Board Staff and the other endorsers of the Consensus Statement on Issue 4, is apparently not to be a "surrogate for competition" but to tax customers to pay for "socially desirable" DSM goods and services that they would not have otherwise purchased. This, Energy Probe noted, is based on an effort to use "planning to improve the ability of market forces to allocate resources". It concluded that this sort of planning can destroy or diminish the ability of market forces to allocate resources.

8.1 BOARD FINDINGS

8.1.1 The Board sees the creation of a separate DSM business as being disruptive of, and likely to detract from, efforts to expedite the development and implementation of DSM plans.

8.1.2 The Board is also of the view that rather than simplifying the regulatory process, the formation of a DSM business would introduce regulatory complexities. The allocation and monitoring of the utilities' costs of supporting such businesses would be difficult, given that the line of demarcation between utility operations and the non-utility business will be less than precise due to the level of interplay between the two enterprises.

8.1.3 The Board notes that the utilities have already demonstrated, to a limited degree, that they can and have successfully pursued demand-side efforts as part of their utility operations. As a result, the Board does not concur with Energy Probe's contention that such efforts need to reside in a separate non-utility division.

8.1.4 The Board, therefore, concludes that the utilities' DSM efforts should properly remain as part of utility operations. Having now thoroughly considered this matter, the Board expects that it will not have to revisit this issue in future proceedings unless or until there is a marked change in circumstances, or significant new evidence is brought forward.

9. ISSUE 5 ALLOCATION OF DSM COSTS

9.0.1 Given that costs will be incurred in the development and implementation of DSM programs, a key question is how these costs should be allocated and recovered. Costs could be narrowly allocated to only those who directly benefit from a DSM measure, be shared across the broader base of a customer class, or be recovered from the ratepayers across the entire utility system.

9.0.2 This issue was included in the Demand-Side Issues List as:

> ***Who should pay for DSM programs? Should the principle of "user pay" apply to DSM programs?***

9.0.3 Two Consensus Statements were submitted on this issue. Board Staff, CAESCO, Centra, CEG, CAC(O), Consumers Gas, OMAA, Pollution Probe and Union agreed to the following Consensus Statement.

Consensus Statement 1

The issue of who should pay for DSM programs encompasses:

a) the appropriate level of contribution/incentives for participants at a program level; and *b) the cost allocation of DSM program costs not recovered by the program after giving consideration to participant contributions.*

Participant Contributions and Utility Incentives

It is desirable that participants who are the direct beneficiaries of a DSM program should bear, to the extent possible, the direct financial burden of the program. Customer contributions should be sought where appropriate, to mitigate program cost impacts on other ratepayers. Providing utility incentives to customers will encourage participation by customers in DSM programs (i.e. increasing net societal benefits). In determining the appropriate level of contributions/incentives, several factors should be considered. These factors would include the impacts of the contributions/incentives on: non-participants, program cost-effectiveness, ability of special customer groups (e.g. low-income, renters, non-profit organizations) to participate, potential for lost opportunities, and the elimination of market barriers that inhibit customer participation.

The use of a DSM portfolio approach is appropriate, where financially self-sustaining DSM programs would support DSM programs which are not financially self-sustaining.

Cost Allocation

The allocation of DSM program costs not recovered from program participants should recognize and be proportional to the distribution of program benefits. These benefits may extend to the system as a whole. Customers outside the target group who benefit as a result of program implementation should bear a commensurate portion of the costs.

9.0.4 The Canadian Petroleum Association, Energy Probe and TWG Consulting Inc. agreed to the following Consensus Statement.

Consensus Statement 2

The principle of individual user-pay within the practical limits of cost allocation should apply to DSM programs.

Positions of the Parties

9.0.5 Board Staff submitted that it is appropriate to extend some portion of DSM costs to the system as a whole, since all ratepayers will benefit from the deferral of future supply-side options and the associated externality impacts. Demand-side and supply-side costs should be treated consistently for cost allocation purposes.

9.0.6 Board Staff suggested that incentives would increase participation and attract specific customer groups that might not otherwise participate in DSM programs. However, incentives should not be so high as to impair the cost-effectiveness of the programs, nor should the utilities simply give away DSM options. Conversely, contributions should be as high as possible without deterring participation.

9.0.7 Board Staff pointed out that the Board has traditionally endorsed rates that are cost-related rather than strictly cost-based, as long as the resulting rates do not place an undue burden on any customer or customer class. Board Staff further noted that the Board has also approved financially non-sustaining distribution and transmission projects for public interest reasons. Therefore, it submitted that some level of rate impact is acceptable, but in no circumstance should it be greater than the rate impact that would have resulted from the alternative supply option.

9.0.8 Board Staff submitted that, wherever possible, the costs of DSM should be allocated according to the impact the program has on peak, seasonal or annual costs. It recommended that the utilities be directed to analyze the cost causality of DSM programs.

9.0.9 Board Staff also submitted that the appropriate level of cross-subsidization should be at the utility's and the Board's discretion to be consistent with the manner in which the Board currently evaluates supply-side options. The diversity and widespread application of DSM programs across all customer classes would help ensure overall equity, as there would be relatively few non-participants. The goal is to find the appropriate level of customer contribution or incentive to ensure that the benefits are produced, while minimizing intra-class and inter-class subsidies.

9.0.10 CAESCO submitted that experience in the U.S. shows that cross-subsidization can become an issue and that the principle of user-pay should be followed. User-pay has always been the basis for ESCO/client contracts, where clients accept their current level of utility bills until the DSM investment has been fully recovered by the ESCO or until the contract expires.

9.0.11 Centra maintained that the cost allocation principles used to allocate DSM costs should be consistent with those used to allocate other expenditures. However, the nature of certain DSM costs may warrant the development of new cost allocation factors.

9.0.12 CEG submitted that customer DSM incentives in an imperfect market are in accord with the "polluter-pay" principle and are, therefore, entirely consistent with a broadly defined user-pay concept. In its view, those customers who choose not to participate in DSM programs impose the largest environmental costs on society and, therefore, should be paying the largest part of the costs of the programs intended to mitigate or offset some of the effects of their actions. It concluded that "the existing situation is rife with cross-subsidy in the form of externalized environmental insult".

9.0.13 Consumers Gas submitted that a strict user-pay approach, as recommended by Energy Probe, is not consistent with the realities of today's marketplace and, if adopted, would unduly limit the scope and benefits of DSM programs. Consumers Gas further submitted that adequate evidence has been brought before the Board to demonstrate the existence of significant market barriers to conservation, and to provide a rationale for a balanced portfolio of utility DSM programs.

9.0.14 Energy Probe recommended following the principle of user-pay for DSM programs to ensure that the twin goals of equity and efficiency are achieved. In its view, even without a fully arms-length relationship between gas distribution and DSM services, significant benefits can be achieved simply by the Board endorsing the broad principle of user-pay, encouraging unsubsidized utility DSM services, and exercising some vigilance to ensure fair cost allocation. Energy Probe noted that subsidies to DSM, like subsidies to supply-side activities, create distorted price signals and encourage inefficiency.

9.0.15 Energy Probe also submitted that "the question of whether society's support for the poor should be in the form of cash, or help with gas bills, or help with weatherization and low-flow showerheads, or food, or education is an important question of public policy, but not one ... which should be answered by the LDCs or by this Board (although ... a recommendation by this Board to the Ontario government could certainly be appropriate)". It concluded: "Much less should the socially preferred form of benefits be financed, in our view, from a tax or monopoly surcharge on gas".

9.0.16 The City of Kitchener stated that some degree of subsidization within and between classes has long been regarded as an acceptable way in which to recover costs and that some subsidization of DSM costs should be regarded as acceptable. It submitted that requiring a DSM portfolio to have no rate impact would confine the burden of subsidization to those who engage in DSM activities and that would tend to discourage participation in self-supporting programs by making these more expensive than they would otherwise be.

9.0.17 The City of Kitchener noted that incentives may be very difficult to justify, and that incentives in the form of "giveaways" and "life-line" rates may be counter-productive in IRP terms. It submitted that the appropriateness of any incentive must be determined on a program-by-program basis in rates hearings. In addition, the Board should not allow the utilities to pass the costs of their DSM programs on to other utilities.

9.0.18 OMAA replied to Union that the use of financial incentives must be combined with, and justified by, good program design, implementation, measurement and evaluation. On the other hand, it submitted that large financial incentives and "give-aways" are sometimes appropriate and necessary to accomplish socially cost-effective DSM. OMAA agreed with Consumers Gas that Energy Probe's position on user-pay is inconsistent with the realities of the Ontario gas marketplace and that the adoption of this position would pose an unwarranted constraint on socially cost-effective DSM.

9.0.19 Union considered it inappropriate to overcome alleged market barriers by "give-aways" or excessively large financial incentives. In Union's circumstances, these would lead to adverse rate impacts, undesirable cross-subsidization and unfair competition with other suppliers of goods and services. Union also rejected suggestions that such problems could be overcome by providing "something for everyone", and argued that this approach would only exacerbate the problems, particularly given its existing base of DSM activities and its relatively low avoided costs. Union further submitted that participation in a DSM program should be the result of the customer's "perception that something of value other than a gift or bribe is being provided".

9.0.20 Union replied that CEG's polluter-pay argument is flawed in that it assumes incorrectly that the use of gas has a net negative impact on emissions, that current DSM program non-participants are inefficient gas users and it also erroneously equates larger use with inefficient use.

9.1 BOARD FINDINGS

9.1.1 The Board endorses the positions put forth in Consensus Statement 1. The Board has traditionally espoused cost-related rates that, to the degree reasonably possible, reflect cost causality. The Board has, however, on many occasions recognized that the public interest is better served by some degree of cross-subsidization being allowed in particular circumstances, so long as it does not reach undue levels.

9.1.2 Given the Board's position on externalities (as set forth under Issue 3) some level of subsidy is likely to be unavoidable. Based on this, the Board is of the view that a strict adherence to user-pay principles as presented in Consensus Statement 2 would be inappropriate. However, the Board believes that the public interest will be best served when the direct beneficiaries of a DSM program bear, to the greatest extent possible, the direct financial burden of the program.

9.1.3 Since there will likely be an array of DSM program proposals, it is impossible to formulate an appropriate set of criteria regarding cross-subsidization that will cover all eventualities. As stated under Issue 2, the Board has concluded that, when determining whether a cross-subsidy is warranted, factors such as the following should be considered:

- Will the immediate impact on customer bills be excessive?
- Is it likely that customer bills will, in the longer term, be unaffected or reduced even if rates increase?
- Will the impact on certain groups, such as low-income customers, be onerous?

- To what degree will the various stakeholders share in the benefits of a particular DSM program?
- Will improvements in the security or overall cost of operating the utility system create benefits beyond the first round impacts of the DSM program?
- Will the long-term net societal benefits of the DSM program override its immediate rate impacts?
- Are the net societal benefits of such magnitude and importance as to give priority to their attainment?
- Do opportunity costs demand prompt action?
- Will an important DSM program be left undone, or poorly done, if a ratepayer subsidy is not provided?
- Will the inclusion of the DSM program contribute to a broader menu of programs and thereby recognize the needs and perspectives of groups such as low-income customers, Aboriginals and farmers, that might otherwise be precluded from participating?
- Will the inclusion of the DSM program take advantage of synergies among programs?

9.1.4 The Board concurs with the use of a DSM portfolio approach where financially self-sustaining DSM programs would support DSM programs that are not financially self-sustaining.

9.1.5 The Board considers it desirable that the portfolio of DSM programs be as broad as reasonably possible to allow as many customers as possible the opportunity to participate and share in the benefits of DSM. The Board suggests that, when structuring their portfolios, the utilities take particular care that ratepayers such as those with low incomes are not discouraged from participating.

9.1.6 When appropriate opportunities arise, for example, if there is a potential to significantly enhance penetration rates, consideration should be given to offering customer incentives. On such occasions the utility must be prepared to present evidence substantiating that the incentive is justified, has been thoroughly researched and will not require undue levels of subsidization from other ratepayers.

9.1.7 In the interests of fairness and competition, the Board believes that intra-class subsidization should be held to a minimum. In this respect, it is obvious that within each rate class there will be customers that have already undertaken conservation measures on a voluntary basis, and at their own expense. On the other hand, these early practitioners have benefitted by avoiding energy costs and thus have achieved some advantage. The Board has considered "grandfathering" and has rejected it due to the attendant administrative complexities. However, the Board would entertain any further proposals as to how to deal fairly with and recognize those who have already implemented conservation measures.

9.1.8 The Board sees value in disaggregating a DSM plan in order to more effectively recognize peak, seasonal and annual cost impacts for the allocation of demand and commodity charges. The Board further suggests that industrial and large commercial customers be grouped separately from small gas users when analyzing DSM program development and delivery mechanisms.

9.1.9 The Board encourages the utilities to make maximum use of energy goods and services suppliers, including ESCOs, when designing and delivering DSM programs. There appears to be little logic to proposals that would encourage a utility to compete with or supplant those existing experts in the field of DSM. Indeed, it would be prudent to investigate ways that the utilities might cooperatively expand the role of the ESCOs by, for example, assisting in the financing and publication of DSM opportunities to both the larger and smaller gas user groups.

9.1.10 The Board's views on customer contributions and on rate impacts are presented under Issue 2.

10. ISSUE 6 INCENTIVES AND DECOUPLING MECHANISMS

10.0.1 Utility earnings are linked to throughput, i.e. deliveries of natural gas. Under current regulatory regimes, a utility's ability to earn above its authorized rate of return is, to the largest extent, dependent on two factors: the ability to restrain its costs to below forecast levels; or the ability to sell more of its energy commodity than anticipated. Given the latter linkage, there is a perceived systemic disincentive for a utility to promote energy conservation and thereby voluntarily limit its throughput.

10.0.2 The questions are, therefore, whether counter-balancing incentives or penalties need to be provided to assure that there is sufficient support for conservation efforts from a utility's management and shareholders, and/or whether a utility's profits need to be "decoupled" from its throughput before DSM can be effectively pursued.

10.0.3 This issue was included in the Demand-Side Issues List as:

> ***Should the utilities receive incentives to undertake DSM programs? If yes, what incentives should there be (i.e. shared savings, compensation for "lost revenues", or an accounting mechanism to unlink gas sales from profits)? Should the utility be rewarded for achieving DSM targets? Penalized for shortfalls?***

10.0.4 The parties subsequently divided this issue into two sub-issues: whether the utilities should receive incentives to undertake DSM programs; and whether the link between the utilities' throughput volumes and revenues should be decoupled. The need for penalties was included in the analysis of incentives.

10.1 INCENTIVES

10.1.1 Board Staff, CAESCO, Centra, the City of Kitchener, CEG, CAC(O), Consumers Gas, OMAA, Pollution Probe, the City of Toronto and Union agreed to the following Consensus Statement, which endorses the use of incentives.

Consensus Statement (Part 1)

1) *Incentives should be made available to the utilities to undertake DSM programs.*

2) *In principle, incentives which are meaningful to the utilities' shareholders and management will serve to encourage the utilities to aggressively undertake DSM programs and to deliver those programs in a cost-effective manner.*

3) *A number of incentive mechanisms are available. The shared savings mechanism is the preferred approach to incentives. However, any appropriately structured mechanism should have as its objective a defined financial reward for a utility whose DSM actions successfully produce net societal benefits in the most efficient manner.*

4) *Based on an assessment of its individual circumstances, in view of the above principle, each utility should have the option of proposing an incentive mechanism which supports its DSM activities. The proposal should be brought forward in the context of a utility rate case.*

5) *At the time a utility brings forward a proposed incentive mechanism for approval, the utility should address the issue of penalties associated with DSM activities.*

Positions of the Parties

10.1.2 Board Staff submitted that incentives are required to encourage the use of DSM programs in place of supply-side options which generate revenue and a return on rate base. Board Staff contended that incentives should be based on actual savings, rather than on the level of DSM expenditure, and that penalties should be used as a disincentive to poor performance or inactivity. According to Board Staff, a shared savings approach would reduce the risk associated with DSM programs.

10.1.3 In response to Consumers Gas' position that equity returns, not incentives, would provide the most appropriate shareholder reward, Board Staff submitted that any recognition of DSM risk should be addressed in the deferral accounts or by way of shareholder incentives.

10.1.4 CAESCO suggested that utilities should assess the benefits and feasibility of financial incentives as a business decision. The utilities should be kept financially whole and not be penalized. However, financial incentives should not discriminate between implementing a program directly through a utility or indirectly, such as when using an ESCO.

10.1.5 Centra submitted that incentives must be significant and obtainable if they are to be effective, and that the introduction of penalties would be counter-productive. Since an application to claim a subsidy will likely require supporting documentation, which can be supplied only by monitoring and evaluation, the utilities may be slow to apply for subsidies.

10.1.6 In its reply argument, Centra emphasized that the creation of a DSM infrastructure would not simply involve a reallocation of existing resources.

Rather, it submitted that there would be a need for additional resources and these would represent a real cost.

10.1.7 CEG argued that incentives are required to ensure that all appropriate DSM programs are developed, not just those that are the most lucrative, easiest, most obvious, or least threatening to the utility or its affiliates. According to CEG, incentives and penalties are necessary to overcome obstacles to conservation (institutional inertia, conflicting interests with gas supply affiliates and market impediments) and to recognize the government's policy on conservation. CEG argued that, although there is a long-run incentive to add rate base either for conservation or supply additions, the current experience is that, in the short run, conservation efforts are discouraged while supply additions are rewarded.

10.1.8 Consumers Gas advocated the use of incentives which would reward the utilities for the successful implementation of DSM. To be effective, an incentive must be meaningful to the utility's managers and shareholders, as well as to the financial institutions, while being fair from a customer's perspective. According to Consumers Gas, an incentive should also be tailored to the specific operating conditions of the utility and be flexible enough to accommodate a range of DSM initiatives. It further argued that a utility should not receive an incentive if its program failed to meet the required performance standards and that, with the possibility of an incentive loss, additional penalties were unnecessary and inappropriate.

10.1.9 In its reply argument, Consumers Gas submitted that a shareholder incentive mechanism could be designed to be equitable and reasonably simple to implement and administer. It argued further that using approved estimates of savings on a per-unit installed basis would expedite the implementation of cost-effective DSM.

10.1.10 Energy Probe submitted that DSM programs should not receive a higher regulated rate of return than investments in supply services. Energy Probe added, however, that subsidized DSM could be used to reduce throughput to a particular customer or class of customers if the marginal price paid by those customers is lower than the marginal cost of supplying them.

10.1.11 In response to the City of Kitchener's statement that regulated utilities have a strong incentive to expand investments in DSM, Energy Probe pointed out that this applies to all utility investment.

10.1.12 The City of Kitchener, while indicating support for the Consensus Statement, nonetheless recommended that proposals for shared savings or other mechanisms that tie penalties and rewards to a DSM program's success be rejected. It took the position that, in fact, the nature of regulation works against the use of a shared savings mechanism. Since measures of program success may not be known for a number of years, the City of Kitchener contended that rewards or penalties would discourage worthwhile investments, or the premature discontinuation of questionable programs. In its opinion, the most effective way to induce DSM investments is to restrict the current level of capital spending on supply-side measures.

10.1.13 The City of Kitchener, however, added that incentives which do not involve revenue compensation, such as deferral accounts or multi-year expenditure commitments, should be allowed in order to reduce the utility risk of not earning its allowed rate of return.

10.1.14 OMAA submitted that the evidence provides more than ample support for incentives, such as the shared savings mechanism. OMAA also stated its belief that a strong incentive structure was required to ensure a rapid evolution from the status quo to a broader spectrum of DSM programs.

10.1.15 Pollution Probe supported the use of a shared savings incentive in the event that the Board did not approve decoupling. However, it pointed out that, in the absence of decoupling, such a mechanism only acts as a contradictory incentive to the coupling of profit and throughput.

10.1.16 Union submitted that, to eliminate any potential disincentives to demand-side programs and ensure equal treatment for demand-side and supply-side options, the utilities would require confirmation that prudently incurred DSM costs could be recorded in a deferral account and recovered in rates. Union noted that bonus mechanisms would be problematic and could result in significant administrative and regulatory burdens. Also, if a utility were permitted to earn its allowed rate of return on DSM, no further bonuses would be necessary at this time.

10.1.17 In reply, Union identified three categories of incentives which currently exist and apply equally to demand-side and supply-side options. These were the opportunity to earn a return commensurate with risk; the desire to minimize costs to remain competitive; and the incentive to minimize the risk of regulatory oversight and scrutiny.

10.1.18 Union further argued that utility management would not consider investments in DSM in general to be less profitable than other investments. In Union's opinion, management would simply consider whether the expected return would be comparable at the time it makes the investment.

10.1.19 In reply, Union countered the argument that unplanned DSM during the rate year may result in a penalty. It contended that substantial variation was not likely within a one-year period, and that if unplanned DSM did occur, it could generate offsetting revenue. Union also pointed out that customer contributions to a successful program could offset any reduction in throughput.

10.1.20 In response to the concern that the utilities might manipulate program performance to maximize profits, Union submitted that such actions would be apparent to the Board and that the utility would be subject to the normal regulatory scrutiny. Union concluded that unplanned opportunities would not be frequent or significant and that it did not anticipate the need to seek recovery for lost revenues on a regular basis.

10.1.21 In response to CEG's assertion that Union was not committed to DSM, Union submitted that the evidence of its participation in DSM development and programs clearly supports the opposite conclusion.

10.1.22 On the issue of affiliate transactions, Pollution Probe described the disincentive that purchases of natural gas by an LDC from an affiliate could have on the aggressive pursuit of energy conservation. Energy conservation would result in a reduction in natural gas purchases from the affiliate, and everything else being equal, the profits to the affiliate, and the corporate organization as a whole, would fall.

10.1.23 Accordingly, Pollution Probe recommended that new affiliate gas supply transactions should be banned in order to ensure that the aggressive pursuit of energy conservation will not be contrary to the financial self-interest of the shareholders of the utilities. Alternatively, it recommended that all new affiliate gas supply transactions should have a "no displacement" clause (i.e. volumes would not be subject to displacement if the utility's requirements are diminished).

10.1.24 Board Staff and the three utilities rejected Pollution Probe's proposed remedies as unwarranted at this time. They noted that the Board and interested parties will have ample opportunity to review affiliate transactions during the public hearing process.

10.2 DECOUPLING

10.2.1 The parties were not in agreement on the issue of decoupling.

10.2.2 Board Staff, CEG, CAC(O), Consumers Gas, OMAA, Pollution Probe and the City of Toronto agreed to the following Consensus Statement on decoupling.

Consensus Statement (Part 2a)

1) Decoupling of profits and throughput volumes should be introduced to remove the existing disincentive to aggressive pursuit and implementation of cost-effective conservation DSM programs.

2) Decoupling mechanisms should recognize, and be tailored to, individual utility operating conditions, markets, and other circumstances. Individual utilities should propose specifics of a decoupling mechanism best suited to their respective circumstances. The proposal should be brought forward in the context of a rate case.

10.2.3 Centra and Union opposed the immediate introduction of decoupling and their Consensus Statement is shown below.

Consensus Statement (Part 2b)

1) Decoupling is not considered necessary at this time to eliminate financial disincentives or attitudinal barriers to the aggressive pursuit of new DSM programs.

2) Disincentives to the aggressive pursuit of new DSM programs can and should be removed through other measures which recognize the utilities business, financial and other risks associated with new DSM efforts and which ensure a fair return for DSM investments.

3) *The greater risks associated with forecasting the impacts of new DSM programs (i.e. program costs, customer participation, program impacts) and the concern of others that DSM effort will be deliberately limited for financial gain, can be addressed through the existing regulatory process and the implementation of a deferral account mechanism. Incentives to reward new DSM initiatives are also possible.*

4) *If in the future the lack of decoupling is considered to be a disincentive by the utility, and the consequences of decoupling are further understood, each utility should be expected to propose a decoupling scheme which suits its own circumstances.*

Positions of the Parties

10.2.4 Board Staff submitted that the current ratemaking process encourages a utility to sell more gas than forecast, and that decoupling would make the utility indifferent to the level of throughput. According to Board Staff, decoupling would benefit the ratepayer as well as the shareholder and permit demand-side options to compete fairly with supply-side options. Also, larger incentives would be required to encourage conservation if decoupling were not implemented.

10.2.5 Board Staff, therefore, argued that decoupling should be mandatory for all three gas utilities in Ontario or, alternatively, that decoupling should be implemented by Consumers Gas on a trial basis. In the presence of frequent rates reviews, Board Staff concluded that decoupling was not a necessary prerequisite for a successful DSM program. However, Board Staff added that decoupling was necessary if the Board wanted to encourage aggressive DSM development. As an alternative to decoupling, Board Staff suggested that a lost revenue adjustment mechanism ("LRAM") might be used to protect the utility against lost revenues associated with conservation.

10.2.6 However, Board Staff contended that the use of LRAMs, as employed in some U.S. jurisdictions, would still not eliminate the throughput incentive and would permit a utility to recover additional revenue from ratepayers, even when the utility was earning more than its allowed rate of return. Since decoupling would reduce revenue volatility and shift economic and weather risks to the ratepayer, Board Staff suggested that a utility's return on equity might need to be reduced.

10.2.7 CAESCO submitted that a decoupling mechanism would shift economic and weather risks from the utility to the ratepayer. CAESCO also argued that decoupling was relatively new and unproven, and that the rationale for decoupling in the electricity industry was not relevant to the gas industry.

10.2.8 CEG advocated full decoupling for all three utilities to eliminate the current disincentive against conservation. In reply to utility submissions that decoupling would have an adverse impact on load building and rate stability, CEG contended that the potential for this negative impact could be easily mitigated and that decoupling would eliminate the perverse impacts of weather and economic cycles on utility management.

10.2.9 CAC(O) agreed that decoupling should be employed in certain circumstances to promote IRP objectives, but it argued that decoupling should not outweigh the broader IRP issues. Accordingly, CAC(O) suggested that the Board should issue guidelines permitting the LDCs to voluntarily decouple if it can be established that doing so would promote the attainment of the goals of IRP in general, and the aggressive promotion of DSM in particular.

10.2.10 Centra contended that decoupling would impose significant changes on the method of regulation in Ontario and could cause more problems than it would solve. Centra concluded that the amount of experience with decoupling was not sufficient to determine that decoupling is appropriate in the current regulatory environment. Centra submitted that the U.S.

experience with decoupling was not useful since it is based on observations which are primarily limited to electric utilities.

10.2.11 According to Centra, the perceived disincentive for a utility to pursue conservation in the period between rates cases is insignificant given the frequency of rate reviews in Ontario. In contrast, decoupling could discourage beneficial gas sales, distort utility decision-making and create perverse incentives which would lead to adverse rate impacts, improper price signals and increased regulatory complexity.

10.2.12 In response to Pollution Probe's contention that decoupling reduces risk, Centra submitted that much of the evidence indicates that the introduction of decoupling could increase total risk to the utility, as it had in many U.S. jurisdictions.

10.2.13 Centra agreed with Union's assertion that the absence of decoupling will not interfere with the aggressive pursuit of cost-effective DSM measures. It also pointed out that CEG's witnesses had originally advanced the notion that full decoupling should be delayed to a later stage in the DSM implementation process.

10.2.14 Centra also agreed with CAC(O) that decoupling was not required in the initial stages of DSM development when one-year rates cases are the norm.

10.2.15 Centra disagreed with Pollution Probe's proposition that under decoupling rate impacts would not likely cause an undue burden on ratepayers and claimed that this was contrary to the evidence.

10.2.16 Centra concluded that decoupling is not required at this time and that, if such a need arises in the future, the utilities will likely be the first to recognize it.

10.2.17 Consumers Gas indicated that, in the course of the proceeding, its position evolved to support for "partial decoupling", i.e. a symmetrical revenue adjustment mechanism, as a response to the disincentive issue. In its view, partial decoupling would avoid the potential negative consequences of full decoupling and ensure that both the ratepayer and shareholder were equally protected against unexpected DSM consequences. Partial decoupling, to some extent, also would address the concerns of those who believe that a utility will not undertake conservation DSM if the existing link between profits and throughput volumes is maintained. In addition, partial decoupling would be consistent with the evolutionary development of DSM, which was endorsed by most participants in the proceedings.

10.2.18 Consumers Gas further submitted that some of the experience in the U.S. supports the idea that partial decoupling may be a more appropriate mechanism. It concluded that partial decoupling would remove the disincentive to pursue socially desirable additional sales, reduce a utility's deferral account balances, address rate variability concerns, reduce utility risk and eliminate concerns regarding changes to the return on equity.

10.2.19 In its reply, Consumers Gas urged the Board to reject the suggestion by Board Staff that decoupling be imposed on Consumers Gas.

10.2.20 Energy Probe submitted that the Board should reject the suggestion that increased conservation requires decoupling and recommended that the benefits of decoupling should be achieved through the further unbundling of gas services and rates.

10.2.21 The City of Kitchener contended that decoupling represents a fundamental regulatory change and that the evidence was not sufficient to force decoupling on a utility. Accordingly, it submitted that the Board should be willing to accept a decoupling proposal, but should not mandate one.

10.2.22 OMAA suggested that the best approach would be to implement decoupling for all three utilities, or, alternatively, to allow one utility to decouple as an experiment.

10.2.23 Pollution Probe argued that, under the current form of regulation, a utility would be financially penalized if it promoted conservation, which is inconsistent with Government of Ontario policy, and contrary to the ratemaking principle that regulation should not penalize utilities for acting in the public interest. To resolve these problems, Pollution Probe recommended that decoupling should replace the current practice of tying profits to throughput volumes.

10.2.24 Pollution Probe argued further that penalizing a utility for promoting conservation is irrational if DSM options are expected to receive the same consideration as supply-side options. Since "status quo rules" motivate utilities to sell more gas, the first step towards improving the regulatory process is to decouple revenues and profits from gas sales volumes.

10.2.25 Pollution Probe disagreed with Centra's assertion that decoupling would lead to excessive rate variability for its large volume industrial customers. Pollution Probe submitted that had decoupling been used, Centra's deferral account balance would have been considerably lower. It was Pollution Probe's submission that Ontario's gas utilities would continue to aggressively promote fuel switching to natural gas if the Board allows decoupling. Pollution Probe also submitted that an LRAM is not superior to decoupling because it cannot completely remove the financial penalty for promoting conservation, and it would unnecessarily increase conservation and regulatory costs.

10.2.26 According to Pollution Probe, if the link between profits and sales volumes were to be severed, the costs of implementing conservation would be reduced. Decoupling would also lower the utility's rate of return, since its business risks would be reduced. Regulatory costs would also drop as a result of the elimination of the need for complex regulatory procedures.

10.2.27 Pollution Probe was not persuaded by the arguments of the three gas utilities that an LRAM was superior to decoupling for four reasons: coupling is a significant disincentive; an LRAM cannot completely remove the financial penalty for promoting conservation; an LRAM would increase the utilities cost of selecting conservation; and it would increase regulatory costs. With regard to the frequency of rates cases, Pollution Probe postulated that annual reviews were unlikely in the future due to the expectation of low inflation rates and the increased desire to reduce regulatory costs.

10.2.28 Union argued that the adverse impacts of decoupling were out of all proportion to any potential lost revenue problem. It maintained that frequent rate reviews of DSM forecasts and alternative accounting methods, such as LRAM, would mitigate any concerns regarding lost revenues between rates cases.

10.2.29 Union argued that decoupling would eliminate an incentive to promote the socially beneficial use of gas and that, in addition to the problems identified by Centra, it would negatively affect competitive gas markets. Union also objected to suggestions that support for decoupling was tantamount to a commitment to conservation. Virtually all gas utilities and most electric utilities that have pursued DSM are doing so without decoupling. Union did not consider that it has, to date, been financially penalized or discouraged from promoting conservation and efficiency due to the absence of decoupling.

10.2.30 Union contended that revenue losses due to unexpected DSM conservation would not be a major concern at this time, given that the promotion of energy conservation and efficiency involves the increased use of gas for new appliances or applications. In addition, Union agreed with Centra that it was highly unlikely that a significant unexpected DSM success would occur between rates cases on a regular basis.

10.2.31 In response to CEG, Union submitted that regulators who instituted decoupling where service quality standards were not in place did so to improve service quality, not to address the conservation disincentive.

10.3 BOARD FINDINGS

10.3.1 The Board notes the emphasis that a number of parties placed on "the perceived disincentive for utilities to aggressively pursue energy conservation". But, the Board also observes that the Ontario gas utilities have to date performed reasonably well in promoting energy efficiency without incentives or other measures to specifically remove the "perceived disincentive". The Board accepts the reasoning that underpins the theoretical perception of a disincentive. However, the Board also observes that the evidence indicates that the disincentive does not appear to be dissuading the utilities from promoting demand-side measures at this time. Having made this observation, the Board, nonetheless, is aware of the need to be vigilant to assure that shareholder interests do not constrain the pace at which DSM programs are identified and implemented in the future.

10.3.2 The Board realizes that, since the Ontario gas utilities are privately owned, it is not reasonable to expect that they should be driven by altruism. In fact, the opportunity for the utility shareholder to earn a reasonable return is essential to the health of the natural gas distribution system in Ontario.

10.3.3 The Board has already allowed that longer-term DSM investments should be included in rate base and thereby earn a return. The Board has also endorsed the use of balancing accounts to shield the shareholder from excessive risks due to uncertain forecasts of DSM costs in the initial years of a utility's DSM plan.

10.3.4 The question remains, however, whether the utilities will meet the Board's expectations and demonstrate at rates cases that their DSM plans are based on aggressive objectives and are being achieved through effective program design, implementation and monitoring.

10.3.5 The Board notes that, although the three major gas utilities were parties to the Consensus Statement on incentives, they were not unanimous in their assessments of the need for incentives and penalties. The Board has concluded that, at this time, it would be inappropriate to require incentive mechanisms or penalties as components of the regulatory regimen for DSM. To offer incentives when they are not requested would impose a needless expense on the ratepayer.

10.3.6 However, if the matter of shareholder incentives is to be pursued, the Board expects that it would be brought forward in the context of a rates case and that this would require a concurrent assessment of the need for penalties.

10.3.7 Should it be established that shareholder incentives are required in order for a utility to commit to an aggressive DSM effort, or to seize an immediate opportunity, the Board would favour the shared savings mechanism endorsed in the Consensus Statement on incentives. Under such an arrangement the Board believes that the shareholders' portion of the DSM program's savings should vary according to the nature or urgency of the program, the market being targeted and the degree of difficulty of implementation. When shared savings are offered, the level of sharing, as well as the method and timing of the determination of the actual savings achieved, should all be established at the time the DSM program is proposed. When it is difficult to segregate the results of the individual programs, sharing on a portfolio basis may be considered. In such an event, the utility's awarded share should be commensurate with the diversified risk of the portfolio.

10.3.8 With regard to the matter of affiliate gas supply transactions, the Board is of the view that, while Pollution Probe claimed a disincentive may exist in theory, there is no evidence that it exists in fact and that it is of sufficient magnitude to justify the proposed remedies. The Board notes that a utility's relations with its affiliates will continue to be scrutinized in the rates cases. Furthermore, the evidence showed that the utilities employ a public tendering process when acquiring new or replacement gas supplies. Having carefully considered the perceived disincentive to conservation that may arise as a result of affiliate transactions, the Board does not expect to revisit this issue unless or until there is a marked change in circumstances, or significant new evidence is brought forward.

10.3.9 On the issue of decoupling, the Board notes that by the conclusion of the hearing, Consumers Gas modified its position to endorse "partial decoupling", i.e. a revenue adjustment mechanism, and supported the consistent treatment of all the major Ontario gas utilities. The Board is of the view that it will be more equitable and less confusing to have a consistent policy across the province.

10.3.10 The Board further notes that the need for decoupling is most pertinent in situations where there are extended periods between rates case reviews. The Board also notes that experiences to-date have varied among the jurisdictions where such programs have been installed. The debate appears to be continuing as to the need for decoupling and which form of decoupling, if any, provides the most appropriate approach.

10.3.11 The Board accepts the evidence that there is only a remote potential for unexpected DSM activity of significance beyond that covered by deferral accounts in the interim between rates cases. Given this, together with the frequency of rates cases in Ontario and the complexities involved in decoupling, the Board is not convinced that full decoupling is warranted at this time.

10.3.12 The Board is of the view that, with the measures which have been accepted herein, the utilities will likely be sufficiently protected to allow them to fulfil their responsibilities to the shareholders, while still being encouraged to proceed with aggressive DSM plans. However, if a utility's lack of revenue protection is shown to be a significant disincentive, the Board is prepared to consider the use of a revenue adjustment mechanism as differentiated from decoupling. In the Board's view, a revenue adjustment mechanism is more consistent with the current regulatory framework in Ontario. As part of any such proposal, the Board will require the utility to fully describe the revenue adjustment methodology and the impact the revenue recovery program would have on the utility's risk exposure and earnings.

10.3.13 As all the stakeholders gain experience with the development, implementation and regulation of DSM efforts, the issue of requiring a revenue adjustment or decoupling mechanism may need to be revisited. The Board expects that if such a need arises it will be brought forward in the context of a utility's rates case.

11. ISSUE 7 MONITORING AND EVALUATION

11.0.1 Market research, monitoring and evaluation are crucial to the management of DSM, most particularly at the early stages when so much is still unknown about factors such as program potential, participation levels and load impacts.

11.0.2 This issue was included in the Demand-Side Issues List as:

> ***How should the utilities define and measure the technical and achievable potential of DSM programs? How should these assessments be incorporated into the forecast demand? How should DSM programs be monitored and analyzed after implementation?***

11.0.3 Board Staff, CAESCO, Centra, CEG, CAC(O), Consumers Gas, the City of Kitchener, OMAA and Pollution Probe agreed to the following Consensus Statement. The City of Toronto agreed with paragraphs 2, 3, 6 and 8 in the Consensus Statement and took no position on the other paragraphs.

Consensus Statement

1. *The definitions of "technical potential" and "achievable potential", which appear at page 103 of the Board's Discussion Paper of September 16, 1991, should be adopted.*

2. *The utilities should attempt to consider as many DSM programs as possible (i.e. identify as much technical potential as possible). The extent of this identification process will be subject to the resources of the utility and the cost/benefit of such an effort. However, the utilities should work collaboratively with each other as well as seeking input from other sources wherever possible.*

3. *The potential programs which are identified should be screened using the appropriate cost-effectiveness tests.*

4. *Free-ridership must be addressed where it is believed to be an issue, and the pre-implementation analysis of a DSM program must account for the existence of free-riders in the context of the design and cost/benefit analysis of the program.*

5. *The utilities should develop estimates of the achievable potential for programs which are determined to be cost-effective. The estimates of achievable potential should be based on the best available information, which may be drawn from other programs undertaken by the same utility, similar programs undertaken by other utilities, and test marketing or pilot programs. The utility may determine that an analysis of the achievable potential is not appropriate for some cost effective programs. In those exceptional cases, the utility will provide the rationale it used to make this determination.*

6. *The utilities should attempt to maximize the achievable potential through program design and implementation, which will involve*

identifying and addressing market barriers. This can be enhanced through collaborative program development and effective monitoring and evaluation.

7. *End-use forecasts are necessary and beneficial, however, their development will take time due to the amount of data required. In the meantime, the utilities should incorporate program specific demand impacts into the existing forecasting methodologies. The utilities should present a discussion on expected activities which are likely to be required to affect end-use forecasting at the first rate case which includes DSM programs. This information should include the cost, data requirements, and time requirements for the proposed levels of end-use forecasting.*

8. *Monitoring and evaluation of DSM programs is necessary to examine the ongoing cost-effectiveness of the programs; to measure the impact on demand; and to determine whether changes to program design are necessary.*

9. *Monitoring and evaluation mechanisms may include one or more of the following: pilot programs, impact evaluation, process evaluation, end-use metering or any other valid monitoring and evaluation techniques. The development of an appropriate monitoring and evaluation plan will balance cost with the need for accuracy, and should be established at the time of program design.*

Positions of the Parties

11.0.4 Board Staff's view was that market barriers, and particularly lost opportunity situations, should be a priority when defining DSM programs. There is a trade-off between identifying DSM potential and keeping costs to a reasonable level. Board Staff cautioned that estimates of the achievable potential and the cost-effectiveness of most programs depend on the assumptions underlying forecasts of participation. Therefore, some sensitivity analysis should be performed. Identifying technical potential was felt to be of limited practicality.

11.0.5 Board Staff argued that Union's proposed method of identifying DSM potential, by addressing only known market barriers, carries a high risk of missing less obvious but still socially beneficial DSM opportunities. Board Staff expressed its belief that Union will not implement DSM beyond its current level.

11.0.6 Board Staff submitted that the Board, as part of its Report, should emphasize the need for the utilities to estimate the market response to their new DSM programs before they are fully implemented. This is especially important for programs which will be in direct competition with commercial suppliers. It was Board Staff's view that increasing a program's costs by raising the incentive level will not necessarily be offset by an equal or greater increase in benefits. Free ridership will not be a serious problem provided that a reasonable attempt is made to account for the effect of free riders when assessing program costs and benefits.

11.0.7 Board Staff also submitted that monitoring and evaluation are required to determine the success or failure of DSM programs. There is a serious risk that inadequate evaluation may allow costly DSM programs to remain in place. Board Staff advised the Board to direct the utilities to describe the monitoring and evaluation mechanisms they intend to employ in order that they can be scrutinized in subsequent rates cases. Specific filing protocols should include DSM program avoided cost analysis, demand forecast impacts and the actual impacts of existing programs on an individual program basis. Board Staff recommended that the utilities determine expected DSM savings under three scenarios (low, medium and high savings) and describe the corresponding impact on supply-side plans.

11.0.8 CAESCO pointed out that estimating the potential for load savings through energy efficiency in the commercial, institutional, and industrial sectors is different from determining the potential for DSM in the residential and small commercial sectors. ESCOs can help ensure that the introduction of new DSM measures are well-planned and coordinated.

11.0.9 CAESCO submitted that the expected load impacts of the DSM options should be incorporated into the utility's demand forecast for the test year, since demand-side measures can be used to meet a utility's forecast demand, particularly in areas where ESCOs are active. In its view, estimating the potential for load savings through energy efficiency in the commercial, institutional and industrial sectors should use an entirely different approach than that used in determining the potential for measures among residential and small commercial customers.

11.0.10 CEG submitted that the utility's filing should describe customer incentives, assumed market penetration, the impact of increased or decreased incentives on penetration and the results of various cost-effectiveness tests. It noted that Union's current approach is to analyze DSM potential only after cost-effectiveness testing and program design. In CEG's view, this approach will not allow the Board or intervenors to evaluate the degree to which the utility's programs are capturing all cost-effective DSM.

11.0.11 Consumers Gas suggested that, for programs which are determined to be cost-effective, utilities should develop estimates of achievable potential using test marketing, focus groups and similar programs conducted by the utility or by others. The best available point estimates of the volumetric impacts of DSM programs should be incorporated into the demand forecast in order to arrive at a "net" volumetric forecast.

11.0.12 Consumers Gas submitted that applying excessive resources to the monitoring function will impair program cost-effectiveness and inhibit the achievement of real results. As experience is gained, design, implementation, monitoring, and evaluation activities can be refined.

11.0.13 Energy Probe argued that the market for natural gas in Ontario (although imperfect) is functioning reasonably well. This market is not subject to market failures that can be overcome with the expertise, credibility, financing or good program design that is available to the LDCs; rather, the "flaw" is that many gas customers can only be induced to buy DSM products and services at below-market prices.

11.0.14 Energy Probe submitted that, in the absence of ratepayer subsidies for DSM programs, there is little need for elaborate follow-up monitoring or analysis. On the other hand, when subsidized DSM programs are involved, it was Energy Probe's belief that there will be many important and difficult questions that will have to be resolved.

11.0.15 The City of Kitchener recommended that the Board require the utilities to formalize a process for the sharing of research and development activities required to obtain the identification of the best possible portfolios. The utilities should also be required to report the results of this work to the Board at rates hearings.

11.0.16 OMAA took the position that it will be exceedingly difficult to realize estimates of achievable potential in the absence of preceding studies of technical potential. It submitted that Union's approach will lead to a scattershot approach which is likely to neglect certain market segments and opportunities.

11.0.17 Union submitted, that since DSM depends upon consumer acceptance, it is more important to focus on examining achievable potential, through consultation, information from other utilities and market research, rather than to conduct studies of technical potential in a vacuum. It adopted the evidence of CEG's witness, Mr. Edgar, that "the best way to learn about achievable potential is basically to develop things in the market and see how they work".

11.0.18 Union also noted that it had previously attempted to develop end-use forecasting models. However, after considerable time and effort, it concluded that such models will not be reliable or practical forecasting tools until there is considerably more detailed and reliable end-use customer and economic data.

11.1 BOARD FINDINGS

11.1.1 The Board agrees generally with the Consensus Statement, but prefers the definitions of achievable and technical potential shown in the appended Glossary. The Board concurs that monitoring and evaluation of DSM programs are necessary to examine the on-going cost effectiveness of the programs; to measure the impact on demand; to address free-ridership; and to determine whether changes to program design are necessary.

11.1.2 The Board notes that there was some disagreement among the parties as to the appropriate emphasis that should be placed on monitoring and evaluation. The Board recognizes that the over-allocation of resources to the monitoring and evaluation function, which includes market research and forecasting, could result in less DSM being undertaken. However, the Board is of the view that the initial results of DSM programs may differ from those forecast and that a lack of monitoring and evaluation could result in the continuation of unsuccessful or expensive programs. As well, the opportunity to learn from successful programs may be lost without credible monitoring and evaluation.

11.1.3 The Board recognizes that there are diminishing returns to the monitoring and evaluation function and that there are difficult technical problems associated with this function. There must be a balancing of the precision of monitoring and evaluation against the resources devoted to this function.

11.1.4 Each portfolio will be assessed initially during the rates case review process. The Board is of the view that the inclusion of the following characteristics in a portfolio is desirable:

- a broad range of programs;
- all programs assessed for their cost-effectiveness;
- appropriate emphasis on information and education programs;
- well-designed and cost-effective monitoring and evaluation of the expected costs and results;
- clear objectives for the individual programs and the overall portfolio; and
- market barriers identified and addressed and potential lost opportunities captured.

11.1.5 Various alternative implementation strategies, which include the monitoring and evaluation of individual DSM programs as well as the overall portfolio, should be identified and compared. The selected DSM portfolio, together with the preferred strategy for its implementation, comprise the DSM plan.

11.1.6 Successive DSM plans will consist of the sum of all existing and any new proposed DSM programs. Each plan should be brought forward for consideration at the rates case, where changes in the portfolio and in the underlying assumptions will be identified and tested. In addition to their individual analyses, new programs which are added to the portfolio in a year should be analyzed as a group, to show the overall impact on the portfolio's costs and results, due to the additions.

11.1.7 As well, each utility should submit an overview of its DSM plan, describing the goals of its DSM portfolio and the objectives for resource planning and customer service. This overview should include specific DSM savings objectives by class of customer. This overview should also include a discussion of the alternative implementation strategies considered for the DSM plan.

11.1.8 In order that forecasting accuracy and program performance can be monitored, the Board expects that each utility will prepare and present a "base case" demand forecast. The base case forecast, which is to accompany the filing of a utility's first DSM plan, should include the on-going impacts of any DSM-related program that was initiated prior to fiscal 1995. NGV programs are also to be included in the base case. The major assumptions underlying this forecast should be explained and price expectations should be described. As discussed under Issue 8, the Board also expects the utilities to provide estimates of alternate fuel consumption by interruptible customers.

11.1.9 Forecasts should be provided for each program and for the overall portfolio showing the pessimistic, optimistic and most likely impacts relative to the base case forecast. These analyses are to include assumptions on factors such as:

- demographics;
- technological change;
- trends in appliance or equipment saturation and use;
- target market;
- achievable potential;
- penetration rate;
- free ridership;
- expected life of the technology;
- delivery mechanism;
- human, hardware and financial resource availability;
- price elasticities;
- overlapping or synergistic efficiency impacts; and
- customer receptiveness and behaviourial changes.

11.1.10 The forecast impacts of each program should be displayed on an annual basis for the first five years of the plan, and at five-year increments to the twentieth year, or the life of the program. Reviews of DSM performance versus forecast, both on an individual program and on a portfolio basis, should be part of each utility's rates case. Estimates of technical potential are to be considered in the evaluation of programs for inclusion in the portfolio, but are not goals in themselves.

11.1.11 For each of the pessimistic, optimistic and most likely cases, the utility should provide estimates of the cost of each program in total and on a per unit of capacity and/or energy savings basis. A monitoring program to track the accuracy of the cost and savings estimates should be defined at the time that a program is proposed. The Board encourages the use of pilot programs, inter-utility collaboration and the other monitoring and evaluation techniques described in the Consensus Statement.

11.1.12 The Board is supportive of efforts by the utilities to improve their forecasting capabilities. Therefore, the Board concurs with the Consensus Statement that each utility should present a discussion on end-use models at the rates case when it files its DSM plan. This discussion should address the degree to which end-use forecasting can be made an integral part of its forecasting approach. It should also include the cost, data and time requirements for the implementation of end-use forecasting.

11.1.13 The Board expects that the utilities will consider and identify occasions when the presentation of forecasts and performance reviews are likely to result in any competitive disadvantage, and when such problems are anticipated, how they might be overcome.

12. ISSUE 8 RATE DESIGN AND DSM

12.0.1 Natural gas consumers, like consumers of virtually all products, react to prices. This raises the issue of whether rate structures can be designed explicitly to influence consumption in accordance with the goals of IRP. There is also the question of whether current rate structures provide appropriate price signals.

12.0.2 This issue was included in the Demand-Side Issues List as:

> ***How can rate design alternatives best be used to manage demand (seasonal, interruptible, declining block, etc.)?***

12.0.3 In response to this question, Board Staff, CAESCO, CAC(O), Centra, CEG, Consumers Gas, OMAA, Pollution Probe and Union agreed to the following Consensus Statement. Energy Probe did not support the Consensus Statement.

Consensus Statement

1. *Rate design alternatives can be used to manage demand, and should be approached gradually on a test market basis. Various rate structures and levels can be used to encourage consumers to adopt different demand patterns. Changes to existing rate structures and*

levels must occur slowly so as to better monitor and evaluate results, and to make any necessary adjustments.

2. *Rates should continue to be cost-related. Any changes in rates should maintain accepted rate design principles, such as cost recovery, fairness, rate stability, and rate shock avoidance.*

3. *Competing objectives that may need to be addressed in rate design include:*

   - *remove any disincentives to energy efficiency and conservation;*
   - *promote energy efficiency and conservation through inverted rates or supporting users of efficient technology;*
   - *make rates more reflective of use, and societal and environmental externality costs, by reducing fixed charges and increasing commodity charges (without raising the total revenue recovery);*
   - *minimize cross-subsidization;*
   - *equity among members of individual rate classes;*
   - *any other utility or public interest objective.*

4. *Interruptible rates are useful in managing demand. The consequences of interruption must be taken into consideration, such as the environmental impact of alternate fuel use. This last factor would depend on the magnitude of alternate fuel use.*

5. *There may be potential risk consequences of changes to rate design, which will have to be evaluated at the time the rate design proposal is made.*

Positions of the Parties

12.0.4 Board Staff submitted that the explicit consideration of conservation objectives would be a new objective in rate design. However, caution is required since the redesigning of rates to encourage the conservation of natural gas may have a detrimental effect if users choose other less environmentally acceptable fuels as a result of increased gas prices at the margin.

12.0.5 It further submitted that seasonal rates are likely to encourage customers to make similar decisions as would be encouraged by the overall DSM portfolio. While equal billing may mute the price signal of seasonal rates, in Board Staff's view, this problem can be substantially mitigated by providing more information to customers.

12.0.6 Board Staff concluded that inverted rates are not a practical consideration at this time, due to revenue instability concerns and the lack of customer acceptance. It further submitted that inverted rates would create equity problems. Even in the relatively homogeneous residential sector, large families and customers who may use gas efficiently, but for more applications, might be penalized.

12.0.7 Board Staff submitted that the current use of interruptible rates should not be altered at present to try to further the goals of IRP. Increased interruptions of natural gas might increase the use of less environmentally acceptable fuels, such as heavy fuel oil. It recommended that the Board direct the utilities to track more closely the use of alternative fuels during interruptions, in order to provide information on the environmental impacts of curtailments.

12.0.8 Board Staff also recommended that the Board should direct the utilities to examine their existing rate structures now to see if they can be further enhanced to improve the efficiency of gas use.

12.0.9 Centra rejected Board Staff's submission on the review of existing rate structures as being premature and recommended that more complete reviews be undertaken as and when rate design alternatives are advanced.

12.0.10 Consumers Gas took the position that the issue of DSM-related rate design experiments is not a significant current concern to most of the active parties in the hearing. It submitted that existing rate design alternatives adequately provide for an enhanced and expanded DSM effort and, therefore, there is no need to alter existing rate structures. Consumers Gas further submitted that it would be imprudent to institute novel rate design alternatives before gaining substantially more experience, both directly and through the monitoring of developments in other jurisdictions.

12.0.11 Energy Probe did not support the Consensus Statement. It submitted that the most efficient demand management will result from a rate design that adheres to the principles of unbundling (i.e. disaggregation of services) and cost-based rates. Rate design should not, in Energy Probe's view, be used as a policy tool for achieving gas conservation. However, to the degree possible, rates should reflect the marginal financial cost of gas and gas services.

12.0.12 Energy Probe argued that rate design options such as inverted block rates ignore the real environmental risks that would result if they cause customers to switch away from natural gas to more environmentally harmful fuels. Energy Probe reiterated its view that instituting surcharges on natural gas rates to fund subsidized DSM is a move away from both the proper role of rate design and the Board's recent laudable tendency to remove from regulated control those aspects of a gas utility's business that are not natural monopolies and can be provided by competitive enterprises.

12.0.13 Union submitted that rate design is a relatively weak tool for promoting conservation, and that it is more important and productive to address the market barriers to wise energy use. Union indicated that it considered its existing rate structure for residential consumers to represent an appropriate balance between competing rate design objectives. Union agreed that it was important to provide customers with information concerning their consumption patterns and the attendant cost consequences.

12.1 BOARD FINDINGS

12.1.1 The Board agrees that accepted rate design principles of fairness, stability and cost recovery should be maintained and that rates must continue to be cost-related. The Board endorses the general consensus of the parties on these issues.

12.1.2 The Board also concurs with the comment in the Consensus Statement that the avoidance of rate shock is a principle of rate design. In addition, the Board notes its acceptance of cross-subsidization (Issue 2) as long as it is not undue, either among customers within a rate class or among rate classes.

12.1.3 With regard to inverted rates, the Board notes that, although this issue was not the subject of a specific proposal, the parties were generally in agreement that inverted rates are unfair in that they do not distinguish between efficient consumption of natural gas and low consumption of natural gas. The Board concurs, and considers inverted rates to be impractical unless there is greater homogeneity within the rate classes.

12.1.4 The Board notes that there is no evidence to suggest that, at present, rate structures are acting as a disincentive to the efficient consumption of natural gas. The Board is of the view that a review of rate structures is not required at this time. However, the Board would encourage the explicit consideration of energy efficiency impacts resulting from rates and rate structures in any future review of rate design. Furthermore, this review should be sensitive to how rate structures might enhance energy efficiency. The Board notes that, for example, seasonal or time-of-use rates have been implemented in other jurisdictions in support of DSM initiatives. Rate design and rate structures must not act as a barrier to energy efficiency measures.

12.1.5 The Board notes that it will be necessary to have information on the use of alternative fuels by interruptible customers in order to estimate the environmental impacts of interruptions. Since alternative fuel consumption may change over time, estimates will need to be updated periodically. In its comments on Issue 7, the Board has requested that this information be provided.

12.1.6 The Board is of the view that customers may be able to make better decisions regarding their energy consumption if they are provided with additional information on their energy use. The Board supports the provision of such information. Among the issues to be investigated are how billing information can be augmented by providing details on consumption in a prior period and to what extent bills can be broken down into capacity, customer and commodity charges.

13. ISSUE 9 JURISDICTIONAL CONSIDERATIONS

13.0.1 To proceed with IRP, the Board must determine its jurisdiction relating to the implementation of IRP by the natural gas utilities in Ontario, and whether legislative amendments may be necessary or desirable. This issue also encompassed the question of the Board's jurisdiction concerning funding for the consultative process.

13.0.2 This issue was included in the Demand-Side Issues List as:

> ***If the Board decides that DSM implementation is appropriate, are there any current jurisdictional constraints which need to be addressed in order to fully implement a DSM effort?***

13.0.3 In response to this question, Board Staff, CAESCO, Centra, the City of Kitchener, CEG, Consumers Gas, Pollution Probe and Union agreed to the following Consensus Statement regarding the Board's jurisdiction over gas utility DSM programs.

13.0.4 The Consensus Statement was supported by the analysis and opinion provided by Mr. Ian Blue, Board Staff counsel (contained in the Discussion Paper) and by the analysis and opinion provided by Osler, Hoskin & Harcourt in the Centra submission.

13.0.5 OMAA and CAC(O) did not support the Consensus Statement.

Consensus Statement

1) The Board has the jurisdiction to approve the test year ratemaking implications of investments and expenditures made by a utility to pursue DSM programs.

2) Further, the Board has the jurisdiction to issue guidelines as to how it intends to evaluate DSM programs for ratemaking purposes within the context of a utility rate case. However, these guidelines cannot fetter the Board's jurisdiction to consider any matter before it, including a departure from the guidelines. The Board should be sensitive to the need for consistency, and the Board should also indicate its support for the longer term DSM programs proposed by the utilities in rate cases.

Positions of the Parties

13.0.6 Board Staff took the position that the two legal opinions that were filed concluded that the Board has the jurisdiction to approve the rate implications of DSM programs and to issue guidelines for the evaluation of such programs. Board Staff observed, however, that there was a lack of unanimity concerning the issue of whether amendments to the Ontario Energy Board Act were required to provide the Board with the jurisdiction to implement a formal IRP process.

13.0.7 With respect to the implementation of IRP over the longer term, Board Staff noted that there are a number of areas which are not well enough defined to permit specific recommendations for amended legislation to be made. These areas include: whether the Board accepts the definition of IRP; the appropriate level of interaction with Ontario Hydro regarding fuel substitution issues; the time frame for an IRP plan; and the process for plan development. Board Staff took the position that, when determining the need for a formal IRP process, the Board will need to evaluate its experience with DSM and determine whether it will be practical, feasible, or necessary to amend the Act in order to achieve the goals of IRP.

13.0.8 Board Staff submitted that it is doubtful whether there is a legal basis for the Board itself to award funding for the consultation process. The existence of a proceeding and the granting of status to an intervenor are prerequisites to an award of funding under the IFP Act. In order to award funding under the IFP Act, the Board would therefore have to find that the consultation process is part of an ongoing IRP proceeding, or that a utility rate case proceeding continued throughout the consultation process. Board Staff recommended that the Board not make such a finding.

13.0.9 Board Staff also submitted that the most practical and legally sound approach would be to allow the utilities to pass through reasonable costs in connection with the consultation process as part of a utility's cost of service. If the Board were to determine that funding is not being appropriately provided by the utilities, it could then invoke the provisions of the IFP Act and assume responsibility for deciding these funding requests.

13.0.10 CAC(O) contended that under the present legislation, the Board does not have the jurisdiction to direct the LDCs to develop integrated resource plans in order to pursue DSM, conservation or load management programs. Nor, in CAC(O)'s view, does the Board have the authority to require either a collaborative working group or a consultative process. CAC(O) also argued that the Board does not have the jurisdiction to approve the cost consequences of some DSM measures or to impose sanctions on the LDCs that refuse to participate.

13.0.11 CAC(O) submitted that proceeding under the current jurisdiction would not achieve the goals of IRP for three reasons: the proposed Board guidelines would not be binding and could be challenged; all DSM measures could be evaluated only in relation to rates; and the maximum societal benefit may not be achieved. CAC(O) contended that a legislated IRP would not be burdensome or complex, and in fact it would simplify rates hearings without adding any more costs than pursuing DSM within the existing legislation.

13.0.12 According to CAC(O), there are several important benefits of a legislated approach to IRP. It would ensure that programs are implemented in a timely and cost-effective manner, which permits conflict resolution, and would provide authority to the regulator to resolve disagreements and ensure that IRP proposals are pursued effectively in the public interest. Legislation would also ensure that there is an opportunity for meaningful public input and that IRP pursuits will not be impeded by jurisdictional arguments. And finally, a legislated approach would reduce the regulatory, business and financial risks of the LDCs.

13.0.13 CAC(O) proposed a detailed legislative framework to address such issues as a definition of IRP, the requirement for consultation in the development of such plans, the use of incentives, the formal evaluation and approval of IRP plans by the Board, and the enforceability of the whole process.

13.0.14 CAC(O) concluded that, pending legislative changes, the Board should issue guidelines on DSM measures that would address the issues of consultation procedures, portfolio preparation, design and evaluation of DSM measures, treatment of DSM costs and intervenor funding and costs.

13.0.15 In reply to CAC(O), Centra observed that the Board already has considerable ability to encourage consultation and that it had not been shown that legislation was necessary to accomplish this goal. Centra also indicated that the pursuit of IRP goals should not be sidetracked by debates about legislative change and the considerable resources that legislative amendments would require. Centra reiterated its position that the best method of funding the consultation process would be for the utilities to voluntarily provide this support.

13.0.16 In its reply, CAC(O) continued to strongly advocate the enactment of legislation to address all aspects of IRP. However, in the interim, it submitted that the LDCs should be required to pursue DSM measures pending the enactment of legislative changes.

13.0.17 CEG submitted that the Board has jurisdiction to implement a DSM effort including decoupling, but it would be desirable to clarify the Board's jurisdiction to offer utility incentives and to adjust a utility's rate of return to foster DSM. The jurisdiction to provide advance funding for a collaborative process prior to a utility's application should be sought, and the ability to convene joint electricity and natural gas hearings should also be made explicit.

13.0.18 In reply to CEG, Centra stated that the legislative changes recommended by CEG should await actual experience, that voluntary funding by the utilities would meet CEG's objectives, and that there is no indication of a disposition on the part of the Ontario government to amend the Act to provide for joint electricity and natural gas hearings.

13.0.19 Centra, in its argument, submitted that to undertake what would inevitably be a time-consuming, complicated and costly process of legislative amendment, would only be justified if there were a specific and necessary objective identified. The history of the Board's exercise of its jurisdiction demonstrates that it has considerable authority to enable the achievement of the DSM objectives that were identified in the hearing.

13.0.20 Consumers Gas contended that the Board has the jurisdiction to approve DSM expenditures and to issue DSM program guidelines for ratemaking purposes. However, Consumers Gas added that the guidelines cannot fetter the Board's jurisdiction to consider any matter before it, including a departure from the guidelines.

13.0.21 In Consumers Gas' opinion, two issues will ultimately require legislative attention. These are: whether DSM assets are considered used or useful in the same way as traditional assets; and whether DSM plans have longer-term stability, if future panels cannot be fettered by previous Board decisions. If DSM investments are open to challenge, the utilities will find it difficult to raise the necessary funds to finance these investments.

13.0.22 Consumers Gas recognized that legislative amendments will require time and, accordingly, it recommended that in the short term the Board should consider DSM proposals under the current legislation. Consumers Gas contended that actual experience with DSM would assist in identifying the necessary amendments. In the long term, however, it submitted that legislative change would be required.

13.0.23 Energy Probe submitted that the Board has sufficient jurisdiction to determine whether DSM activities should be removed from a utility's regulated operations and to insist that utilities should be guided by the principles of user-pay and rate minimization. However, if equal treatment of supply-side and demand-side options is a requirement of the regulatory process, a clear legislative mandate would be required.

13.0.24 With respect to the issue of DSM subsidies being outside the Board's mandate, Energy Probe took the position that the optimization of social welfare was a government function and that the Board should concentrate on consumer protection.

13.0.25 The City of Kitchener recommended that the Board proceed with the introduction of IRP without an alteration of its jurisdiction at this stage. The City of Kitchener also submitted that approvals for long-term DSM programs may be required in rates cases and that the Board should be willing to approve a program for a number of years, unless circumstances arise which warrant a reconsideration of the original approval.

13.0.26 OMAA reiterated its position that legislative change was necessary to ensure that IRP would take place, but indicated that, until the current legislation is revised, all parties should proceed with the IRP process. OMAA pointed out, however, that there are risks in a process that does not have clear legislative authority. For example, parties may not feel that they have adequate input in the planning process and this may lead to the process becoming contentious. If this happens, the Board may be asked to deal with disputes that it does not have authority to resolve.

13.0.27 Union asked the Board to endorse the need for consistency and to express support for longer-term DSM programs. Union stated that it supports amendments to the Act to indicate clearly that DSM deferral accounts, together with the cost of financing those balances, should be recovered in rates. However, Union submitted that, while it supports such changes to the Act, they are not a necessary condition precedent to its pursuit of new DSM programs.

13.0.28 Union submitted that neither need nor justification had been shown for the additional regulatory complexity or the cost that would result from the further formalization of IRP through legislative measures, particularly in view of the LDCs' support for virtually all of the important provisions of the Consensus Statements and for the goals of IRP.

13.1 BOARD FINDINGS

13.1.1 The Board concurs with the Consensus Statement as an accurate and reasonable statement of the Board's current jurisdiction to consider and evaluate DSM programs in rates cases.

13.1.2 The Board, like other administrative tribunals, can exercise only that jurisdiction which has been conferred on it expressly or by necessary implication by statute. There is currently no specific authority in the Ontario Energy Board Act, or any other statute, which would permit the Board to order Ontario LDCs to develop and file integrated resource plans according to criteria established by the Board. IRP, like the deregulation of natural gas markets, was not something that could have been contemplated when the Act was enacted in 1960.

13.1.3 The Board does, however, have the authority under section 19 of the Ontario Energy Board Act to receive evidence as to the prudence of investments and expenditures made by a gas utility in the implementation of DSM programs, and to evaluate those programs as part of an application to approve or fix just and reasonable rates and other charges.

13.1.4 Where DSM is an issue in a rates application, the Board has the jurisdiction to require evidence showing that the utility is prudently carrying out DSM planning and that such planning has regard to the guidelines issued by the Board, including those for consultation.

13.1.5 Further, the Board can issue guidelines as to how it intends to evaluate DSM programs for ratemaking purposes. Such guidelines cannot fetter the discretion of the Board to decide any matter that comes before it based on the facts adduced at the hearing. The Board recognizes, however, that consistency in Board decisions is desirable. The Board will strive to achieve consistency in the application of DSM guidelines without hindering the ability of any individual panel of the Board to reach its conclusions based on the evidence before it.

13.1.6 The Board also recognizes that some DSM planning is by its nature long term and that DSM expenditures and investments may be spread over several years. This gives rise to the possibility that the same DSM program may come before several panels of the Board. While no panel can fetter the discretion of a future panel, the Board supports long-term DSM planning and is confident that prudent long-term investments by gas utilities in DSM programs will be fairly considered and that panels in rates cases will take account of the need for consistency in the treatment of long-term plans.

13.1.7 The Board notes that a number of suggestions for legislative amendments have been made in this proceeding. For example, several parties would like to see the Act define "Integrated Resource Planning" and include provisions giving the Board explicit jurisdiction to order utilities to develop integrated resource plans and to bring these plans before the Board for approval. Other parties were concerned that existing legislation might not give the Board jurisdiction to provide incentives or adjust an LDC's rate of return based on DSM performance. Some concern was also expressed that the collaborative process envisaged in DSM planning might require legislative sanction to ensure compliance.

13.1.8 The Board recognizes that there is a need for certainty and clarity in IRP and that this may ultimately only be achieved by legislative change. At this stage, however, it is the Board's view that it is too early in the development of IRP to recommend such changes. The Board fully expects that, as IRP evolves in Ontario, the need for, nature and extent of appropriate legislative amendments will become clearer. The experience gained in the consideration of DSM planning in rates cases will furnish valuable guidance for any future legislative change.

13.1.9 However, the Board notes that, although it can make recommendations for legislative amendments, it is the Government of Ontario and the Legislative Assembly that will ultimately determine whether changes will be made, and what those changes will be.

13.1.10 It is the Board's view that it would not be wise to wait for legislative change before beginning to implement IRP. As has already been pointed out, the Board has sufficient authority under existing legislation to consider DSM programs in the context of a rates application. It is the Board's opinion that this is a satisfactory basis for beginning the process of implementing IRP.

13.1.11 Several parties raised concerns about the provision of advance funding for consultation with the utilities on DSM planning. The Board notes that the power to award funding under the Intervenor Funding Project Act is predicated on the existence of a proceeding before the Board, and at the time of the consultation process envisaged, there would not yet have been an application by a utility. Hence, the Board would have no jurisdiction under the IFP Act to award advance funding for consultation prior to the filing of an application.

13.1.12 It is the Board's view that the preferred funding mechanism is for the utilities to fund directly the pre-application consultative process, which they have indicated a willingness to do. The Board is confident that panels hearing rates applications will give fair consideration to the inclusion of costs prudently incurred for consultation.

14. ISSUE 10 IMPLEMENTATION OF IRP

14.0.1 In order for effective IRP plans to be developed and implemented, attention needs to be directed to the process that should be employed. When setting the scope for the overall process at the initiation of these proceedings, the Board announced that it would use a "building block" approach whereby the study of DSM planning would be investigated as the first step toward a fully integrated plan. The challenge at this time is to identify the process to be employed when developing demand-side management plans. This procedural question raises issues such as whether DSM planning should be a distinct activity or whether it should be part of the current rate review process.

14.0.2 This issue was included on the Demand-Side Issues List as:

> ***Should the Board proceed with the implementation of IRP and if so, how should it proceed?***

14.0.3 In response to this question, a number of different Consensus Statements were put forward by various groups. These statements were divided into two main parts, and the second of these was divided into three sub-parts.

14.0.4 Board Staff, CAC(O), CAESCO, CEG, Centra, the City of Kitchener, Consumers Gas, Pollution Probe and Union agreed to Consensus Statement (Part 1).

14.0.5 Board Staff, CAESCO, Centra, the City of Kitchener, Consumers Gas and Union agreed to Consensus Statement (Part 2a).

14.0.6 CAC(O), CEG, Pollution Probe and OMAA agreed to Consensus Statement (Part 2b).

14.0.7 Board Staff, CEG, CAC(O), Consumers Gas, OMAA and Pollution Probe agreed to Consensus Statement (Part 2c).

Consensus Statement (Part 1)

> *The Board should issue a report with DSM recommendations and guidelines upon the completion of this phase of the IRP proceedings.*
>
> *One of the guidelines would be the expectation that each utility would come forward at its next rates case with DSM programs or plans. The scope of these plans will be dependent upon the time available to each utility.*
>
> *Further, each utility would undertake meaningful discussion or consultations with representatives of its known interested parties or the representatives of known significantly affected parties in advance of filing a DSM proposal. These discussions are intended to improve program design, increase participation rates and reduce hearing time. These discussions would focus on how the plan should be developed based on the Board's guidelines, and would include such issues as program identification, cost effectiveness analysis, program design, program monitoring and evaluation, and proposed cost recovery.*

At a utility specific rate case, the Board could approve the test year impacts of those aspects of the DSM program which it considered to be just and reasonable, with consideration given to the guidelines issued in E.B.O. 169-II. Ongoing cost recovery would be the subject of future rate cases. Pre-approval of the ratemaking impacts of a DSM program or plan beyond the test year is not possible, given the Board's current jurisdiction. Such pre-approval is also not advisable, as there should be ongoing scrutiny of the program's costs and results. This scrutiny will be achieved through the ongoing program monitoring and evaluation.

There may be potential changes in risk (e.g. forecasting, business, regulatory, jurisdictional) arising from the implementation of DSM or IRP, which will have to be evaluated at the time DSM or IRP proposals are made by the utilities.

Consensus Statement (Part 2a)

The Board does not have the jurisdiction to implement a formal IRP process under its current legislation. However, the necessity for a formal process cannot be determined yet. Given the difficulties associated with getting legislative change enacted, the Board should proceed to pursue the goals of IRP and at the same time continue to evaluate whether a more formal process is required.

It cannot be determined now whether further generic hearings on other aspects of IRP will be necessary in order to pursue the goals of IRP. The Board should proceed with issuing guidelines and examining DSM plans in individual utility rate cases, without making a determination in this proceeding as to the need for further generic proceedings.

After the first round of DSM plans is considered, it may become apparent whether further generic investigation into supply side or integration issues is required (e.g. fuel substitution, externalities). The Board should make this determination in consultation with the interested parties.

Consensus Statement (Part 2b)

The Board should pursue legislative change to ensure that it has the legislative authority to enact a full IRP process which would allow for the establishment of rules and regulations for IRP on a multi-year basis.

It is imperative that the Board have the jurisdictional authority at hand to fully implement a comprehensive IRP process. The existence of a clear legislative mandate will in and of itself increase the likelihood that IRP goals will be achieved.

Legislative authority supporting multi-year IRP plans would reduce regulatory risk and reduce the uncertainty of cost recovery for utility DSM expenditures.

Consensus Statement (Part 2c)

The Board should use its current legislative mandate to the fullest extent possible to pursue the goals of IRP.

Decoupling the link between distribution revenues and natural gas throughput volumes and the implementation of a strong DSM incentive structure will reduce the likelihood of needing to apply a formal, prescriptive IRP process to achieve IRP goals.

Positions of the Parties

14.0.8 Board Staff submitted that, with respect to the implementation of short-term DSM programs, the Board should set parameters in its guidelines to ensure broadly-based and meaningful participation by interested parties in the consultation process. The consultation process and results should be documented in a report to be included in the evidence supporting a utility's DSM plan at a rates case.

14.0.9 Board Staff submitted that the Board should indicate that any costs for undertaking consultations would be eligible for inclusion in the utility's cost of service after being subjected to examination in a rates case. The utility should be responsible for the control of these costs. The Board's current Cost Assessment Guidelines represent sensible criteria for the utilities to use when considering funding requests. Any party that is excluded from the consultation process through insufficient funding would still have the option of applying for intervenor funding in a rates case. In Board Staff's view, input from such a party would be one of the factors the Board should consider when determining whether the utility had properly undertaken its consultations.

14.0.10 CEG submitted that this proceeding has not adequately considered the supply-side and avoided cost aspects of IRP. Supply-side aspects will inevitably emerge as issues. By formalizing the full IRP process, the Board can ensure timely public involvement and encourage pre-submission collaboration. This, according to CEG, can minimize regulatory risks, as well as social and customer costs.

14.0.11 CAC(O) stated that for the consultative process to be successful, funding must be provided to the participants. CAC(O) suggested that funding should be provided under the IFP Act and should be recoverable by the LDCs in their rates.

14.0.12 Consumers Gas stated that effective consultation should tend to ensure a more efficient regulatory process with respect to DSM, and a higher prospect of success before the regulator. It recommended a structured consultative process that is practical, rather than one which encompasses extensive formal collaboration on all DSM-related issues.

14.0.13 It was Consumers Gas' view that attaining the benefits of IRP, which are predominantly related to DSM, can be fully accommodated within the context of a rates proceeding, both in the short term and in the long term. A separate IRP hearing would only add to the complexity and the cost since, to some extent, the examination of certain DSM and IRP issues would have to be repeated in a rates case. Separate IRP hearings would also not be conducive to getting on with DSM initiatives in the nearer term.

14.0.14 The City of Kitchener stated that, while the Board can expect the level of DSM investment to be increased in the future, it should be recognized that there are a number of limiting factors. First, there was no suggestion at the hearing that there were types of DSM programs which were being ignored by the utilities. Accordingly, the parties should not be surprised if the portfolios presented at the next rates cases contain programs similar to those which currently exist. Second, the initiative in the gas industry will be limited by the degree of IRP applied to other fuels. If all fuel prices do not reflect the cost of externalities to some degree, then the more harmful environmental fuels will prevail.

14.0.15 The City of Kitchener submitted that the requirement for consultation should not become a formal component of rates case preparation. The initiative and responsibility for developing programs of any kind, including DSM proposals, must reside with the utility's management. Consultation should be seen as part of the ongoing responsibilities of the marketing departments in each utility.

14.0.16 OMAA indicated that rates case hearings would be a limiting forum for the IRP process, since OMAA would be practically and financially unable to participate in each individual rates hearing. Also, it was concerned that insufficient attention will be paid to the IRP process in the midst of the numerous competing priorities in rates case hearings.

14.0.17 OMAA emphasized that its members are likely to be significantly affected by the outcome of this process, and can contribute a unique expertise and perspective to assist in the development of IRP. However, it does not have the resources to ensure that its concerns will be considered. In OMAA's view, its misgivings in this regard were illustrated by the experience to date with the ad hoc externality working group. While OMAA was invited to participate in this group, such participation has been effectively foreclosed by lack of financial resources. Based on its experiences, OMAA was uncertain whether meaningful consultation will actually take place in the development of the IRP process.

14.0.18 OMAA suggested that consultation should occur on three levels. First, the Board and the LDCs should make a special effort to understand OMAA's concerns and orientation, through consultation at the community level. Second, OMAA members who are gas users should be consulted in the development and implementation of DSM programs, just as other groups of consumers are consulted. Third, the Board should establish a meaningful process for consultation with OMAA's members regarding the identification and valuation of social and environmental externalities.

14.0.19 OMAA argued that, for the IRP process to be effective, sufficient funding must be provided for consultation, as well as for legal and expert support to the affected parties.

14.0.20 In reply to OMAA, Board Staff submitted that meaningful consultation with OMAA's constituency will be very difficult to pursue as OMAA has not yet enumerated its membership. Therefore, in Board Staff's view, OMAA must help the utilities identify and communicate with the affected parties. Board Staff went on to submit that it is important that the Board receive OMAA's input on these matters, although direct consultation with individual Board members may not be appropriate.

14.0.21 Union, consistent with its approach to supply-side programs, proposed that it would provide funding where appropriate to facilitate participation by interested parties in the consultative process relating to DSM, and seek the recovery of costs in future rates cases. Union asked for the Board's endorsement of this approach.

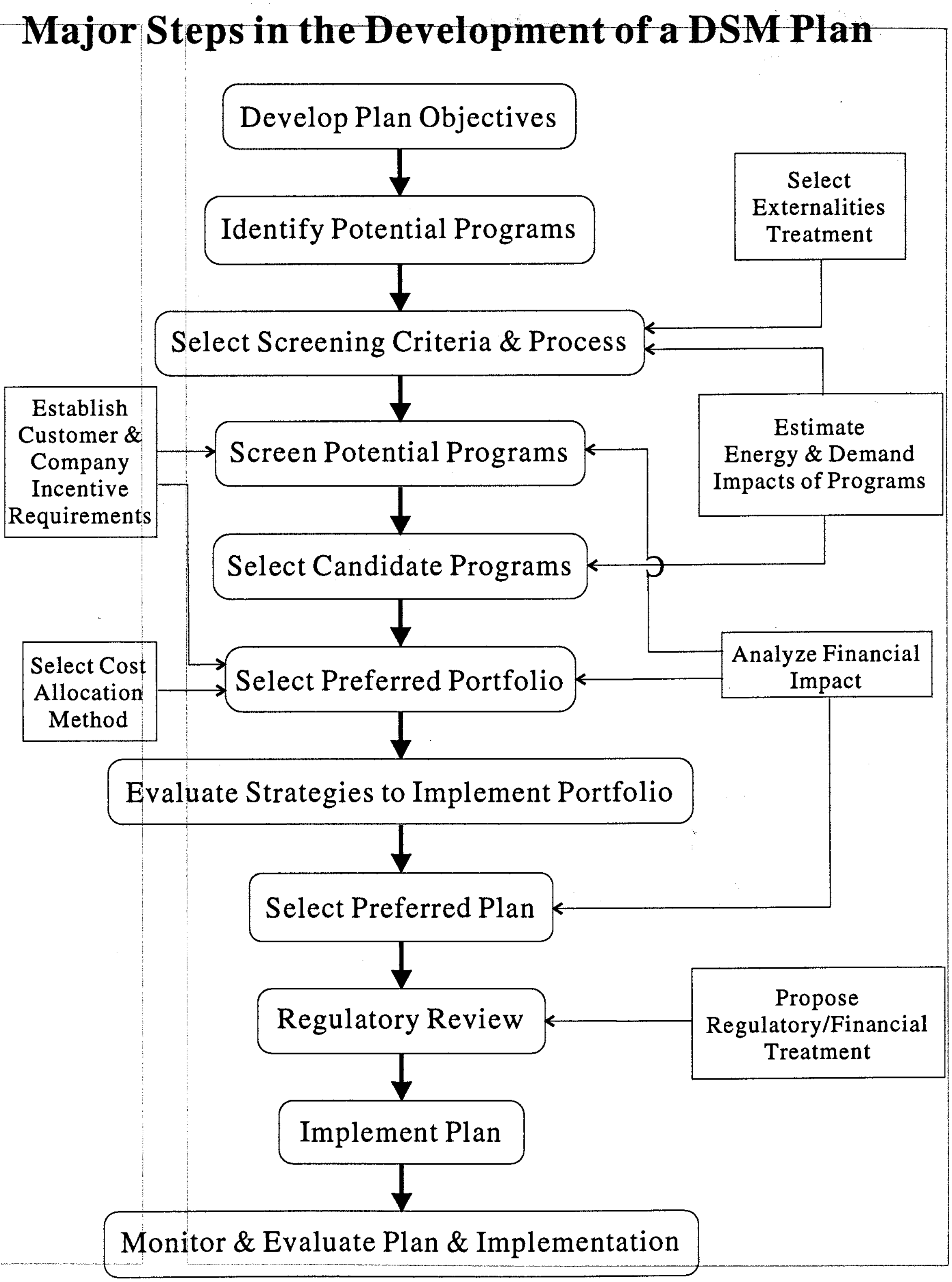
14.0.22 Union suggested that future generic hearings on supply-side integration matters will not be required. It further noted that the major elements of IRP, with respect to the integration of plans, will also be in place through the process of estimating avoided costs and employing those estimates in DSM program evaluations. Union indicated, however, that subsequent workshops might be beneficial.

14.1 BOARD FINDINGS

14.1.1 In the preceding chapters of this Report, the Board has set out its views on the key elements of DSM as identified in the Demand-Side Issues List. The Board now expects the utilities to proceed with the development of their individual DSM plans for presentation at rates cases. The Board has set out guidelines for this process in Chapter 15.

14.1.2 In order to assist the utilities in the development of their DSM plans, the Board suggests a planning framework comprised of the major steps that the utilities should carry out. This framework, depicted in Figure 2, presents the planning steps in a linear fashion for illustrative purposes, but the Board recognizes that the process may be non-linear and iterative.

FIGURE 2


Major Steps in the Development of a DSM Plan
Develop Plan Objectives
Identify Potential Programs
Select Externalities Treatment
Select Screening Criteria & Process
Establish Customer & Company Incentive Requirements
Screen Potential Programs
Estimate Energy & Demand Impacts of Programs
Select Candidate Programs
Select Cost Allocation Method
Select Preferred Portfolio
Analyze Financial Impact
Evaluate Strategies to Implement Portfolio
Select Preferred Plan
Regulatory Review
Propose Regulatory/Financial Treatment
Implement Plan
Monitor & Evaluate Plan & Implementation

14.1.3 Using this framework, a utility should be able to select a preferred portfolio. The selected DSM portfolio, together with a strategy for its implementation, comprises the DSM plan.

14.1.4 The Board expects each utility to file its DSM plan no later than at the time of its fiscal 1995 rates case application. The Board recognizes that, given the timing of its fiscal year, Union, in particular, may find it difficult to comply with this timetable. Any request for extension should be made by a utility as soon as possible after receiving this Report. The utility should offer alternatives that can allow a DSM plan, or components of a full plan, to be implemented in advance of its fiscal 1996 rates case.

14.1.5 With regard to consultation, the Board encourages its use and has endorsed the formation of a joint Collaborative. While there is an urgent need to apply a consultative effort to the measurement and monetization of externalities, as well as the development of qualitative assessment methodologies, the potential advantages of consultation on DSM matters extend beyond that need. The Board expects the utilities to consult with appropriate parties in an effective manner to obtain meaningful input related to each of the major steps of the DSM planning process before irreversible decisions related to them are made. How consultation on the development and implementation of DSM plans, beyond the issues covered by the Collaborative, is to be carried out is left to the utilities to propose and justify. The Board's main concern is that there be meaningful and effective consultation.

14.1.6 With regard to the joint Collaborative, the Board expects that the utilities will move quickly to define what interests should be part of the Collaborative, and who should represent them.

14.1.7 The Board further expects that, once formed, the Collaborative will reach agreement on its terms of reference, timetable, budget, and workplan and that it will be able to submit its report on these matters by September 30, 1993 to the Board and the parties in the E.B.O. 169-III proceeding.

14.1.8 The Board encourages the Collaborative to strive to submit its final report to the Board and the parties by February 28, 1994 in order that the results can be incorporated in the examination of DSM plans for fiscal 1995.

14.1.9 In the event that the above deadlines are found to be unrealistic, the Board expects the utilities to make this known as soon as possible and, when doing so, to define the causes of delay and to jointly commit to a revised timetable.

14.1.10 The Board has considered the suggestion that plans be presented and reviewed at hearings that are specific to IRP or DSM, as opposed to incorporating these matters into rates cases. The Board has concluded that a utility's DSM effort must be viewed not only with regard to the external circumstances at the time, but also in relation to the utility's current operations. In the Board's view, a utility's DSM plan must be dealt with in the context of a rates case to assure that a proper perspective is maintained with regard to related matters such as rate impacts, human and capital resource availability, and working capital demands. Also, the Board does not see the added costs of separate hearings as being in the public interest. The Board also notes that there may be jurisdictional constraints to hearing IRP-related matters outside the context of a rates case.

14.1.11 The Board has also considered OMAA's recommendation that, in addition to the consultation on externalities, meetings be arranged to provide opportunities for the Board to gain insight into the orientation and needs of the Aboriginal community. The Board concurs that it would be valuable for it to increase its understanding of this segment of society. However, it is quite likely that other sectors might validly claim that their perspectives and needs are not fully appreciated. In the Board's view, it would be impractical to attempt to conduct meetings, of the type which OMAA proposes, with each interest group. Further, if the Board were to meet only with OMAA, this might give rise to claims by other parties that OMAA was being afforded unfair access to the decision-maker.

14.1.12 Thus, while it might be productive for OMAA to host occasions for the utilities, Board Staff and other parties to gain a better understanding of OMAA's "special concerns and orientation to gas related issues", it would be inappropriate for Board Members to meet individually with OMAA. The Board also notes that, if OMAA holds such meetings, the question arises as to whether it would be appropriate to require that natural gas ratepayers underwrite the cost, since the advantages to be realized by such meetings would be disproportionately to the benefit of OMAA and its constituents. Thus, the Board suggests that OMAA should investigate alternative ways to fund these meetings.

14.1.13 In conclusion, since the individual utilities will be held accountable for the development and implementation of their DSM plans, the Board feels it is proper to allow them the freedom to pursue these efforts in the manner that they feel is most appropriate. The wisdom, prudence and cost of the course of action they choose will, however, be subjected to future reviews by the interested parties and the Board.

14.2 FUTURE ACTIVITIES

14.2.1 The Board views the initiation of a formal DSM planning process as being only the first of many steps toward a fully integrated resource plan. The Board intended to convey this message when, at the outset of these proceedings, it referred to the study of DSM planning as the first of the "building blocks" of IRP.

14.2.2 Once the initial DSM plans have been filed by the utilities, and there is sufficient experience to assure that DSM planning is on a firm footing, progress toward a full integrated resource plan can continue. The next issue to be addressed is expected to be a review of the utilities' supply-side policies, activities and expenditures to confirm that these are consistent with least-cost planning principles.

14.2.3 A specific review of the methodologies prescribed in the Board's E.B.O. 134 Report will likely be required as part of the review of supply-side issues. Depending on the Board's calendar, this review may be undertaken as a separate generic hearing or as a part of the continuing IRP investigations.

14.2.4 Once both the demand-side and supply-side components of IRP have been investigated, the final phase of these proceedings, i.e. the combination of these elements into a formal integrated resource plan, can commence.

14.2.5 In the interim, and as further experience is gained, the Board recommends that government consider at least the following:

- government regulation to establish targets for allowable CO_2 emissions;
- additional provincial, inter-provincial and federal policies, standards and fiscal measures to further promote and coordinate efforts toward energy efficiency and the protection of the environment;
- legislative action to establish a regulatory mandate to oversee gas IRP and its underlying issues; and
- clarification of the roles of the involved government agencies in order to effectively coordinate IRP in the natural gas, electric power and, if possible, the alternate fuel industries.

14.2.6 It is the Board's hope that through the DSM efforts initiated in this proceeding, and the establishment of a consultative process, common perspectives will emerge to guide governments as they address the need for further action regarding wise energy use and environmental protection. Toward this end, the Board has been encouraged by noting that, notwithstanding the lively debate on a number of the specific issues, there appears to have been unanimity among the participants in this proceeding on the underlying principles and objectives of the demand-side management of natural gas use in Ontario.

15. GUIDELINES

15.0.1 At the conclusion of the Phase III hearing, the Board asked the parties to address an additional issue in their arguments. In order that the Board might have the benefit of the collective wisdom of all the participants when charting the future course of DSM, the Board asked that each party respond to the following question:

> ***If the Board were to decide to call for the development and submission of DSM plans by the utilities, what issues must be addressed by the Board in its E.B.O. 169 Report, and what specific guidelines must be provided?***

Positions of the Parties

15.0.2 All parties endorsed the need for the Board to provide clear guidelines to assist the utilities in the preparation and implementation of their DSM plans. The parties, in response to the above question, generally restated their submissions on the ten issues in the Demand-Side Issues List, which they recommended be incorporated into specific guidelines.

15.0.3 CEG recommended a detailed listing of information requirements to be included in utility filings. In CEG's view, utilities should not simply provide a single preferred plan. Alternatives should be presented in detail.

In particular, utilities should indicate how they intend to capture lost opportunities. They should also describe:

- program alternatives and their costs;
- alternative bundles of measures for each program;
- alternative measure costs;
- customer incentives by measure;
- the assumed penetration rate for each program and measure in each customer niche;
- an evaluation of the impact of increased or decreased incentives on penetration for each measure; and
- the results of various cost-effectiveness tests for each measure, program, portfolio and alternative.

15.0.4 CAC(O) indicated that it supported a similar approach, and OMAA expressed its agreement with CEG's proposed filing requirements.

15.0.5 Consumers Gas and Centra replied that a detailed proposal on filing requirements is premature. Centra further submitted that, in any event, the cost of presenting such an extensive analysis is likely to be prohibitive.

15.0.6 Union submitted that guidelines should be sufficiently flexible to allow each utility to pursue DSM in light of its own particular circumstances. As well, the guidelines should have sufficient flexibility to recognize that DSM should be permitted to evolve on the basis of experience.

15.1 BOARD FINDINGS AND GUIDELINES

15.1.1 The Board expects initial DSM plans to reflect the concerns and views which the Board has identified herein, or in the alternative, to clearly explain why acceptance of any of the Board's recommendations is considered inappropriate.

15.1.2 The Board considers the list of guidelines proposed by CEG to be too detailed and onerous for adoption at this phase of the process, and that the time and expenditure that would be required to respond to CEG's proposals would be excessive.

15.1.3 The following list summarizes the major concerns and views of the Board. It is being provided as a recommended guide for the utilities as they prepare their individual DSM plans, but does not supersede the previous chapters where each issue is discussed in greater detail.

15.1.4 Appropriate Costing Methodology for Demand-Side Options

- The benefits of DSM should be the avoided supply-side costs including capital, operating and energy costs.
- Avoided tolls and demand charges should be included as avoided costs of a DSM program.
- The avoided upstream costs of TCPL and natural gas producers should be identified when they are known, but should not be incorporated.
- Long-run avoided costs over the useful life of a DSM program should be used when defining DSM benefits.
- Emphasis in the analysis should be on the first five years of a DSM program and portfolio when evaluating costs and benefits, as well as their performance versus forecasts.
- A break-even analysis of each DSM program should be provided.

15.1.5 Cost-Effectiveness Tests

- When considering which potential programs should be screened for cost-effectiveness and incorporated in a DSM portfolio, consideration should be given to:

  - achievable potential;
  - the capture of potentially lost opportunities;
  - synergism among programs; and
  - the breadth of the portfolio.

- Once identified, potential programs should be subjected to a screening process which incorporates the following recommendations:

  - The Societal Cost Test should be a first screen (Screen 1) and used as a pass/fail hurdle (i.e. it would be unreasonable to pursue further a program that does not have a net benefit to society).

  - Social costs and benefits should be considered and treated in an equivalent manner to environmental costs and benefits.

  - Only those direct and indirect externality costs and benefits that are significant should be included in the SCT.

  - A qualitative assessment of each DSM program, including all program costs and benefits, should be carried out to produce a non-monetary conclusion on net societal benefit.

  - Programs that pass the SCT should next be subjected to Rate Impact Measure testing (Screen 2).

  - Programs that fail the RIM test may be further considered if the rate impact they would impose is not undue and if second round costs do not exceed the first round net societal benefits (Screen 3).

- The net societal benefit per dollar of subsidy should be provided for each program that fails the RIM test.

- Programs that fail Screen 3 should be further considered as candidate programs if they provide qualitative benefits such as: improved safety and system reliability; avoidance of lost opportunities; recognition of critical or important societal benefits; the need to broaden the DSM portfolio; or support for government policy (Part 1 Screen 4).

- Each program which has passed Screens 2, 3, or 4, Part 1 should be assessed to determine the program's suitability as a candidate for further consideration in comparison to the other surviving programs.

- All programs should be assessed from a pragmatic point of view regarding the likelihood of their acceptance and success.

- Candidate programs should be consolidated into potential portfolios, for evaluation. Each portfolio should be subjected to sensitivity analyses prior to the selection of the ultimate portfolio (Screen 5).

- The screening process and the assumptions used in carrying it out should be clearly documented and presented at the rates case.

• When assessing what constitutes a reasonable rate impact for programs that have failed the RIM test, consideration should be given to questions such as:

- Will the immediate impact on customer bills be excessive?

- Is it likely that customer bills will, in the longer term, be unaffected or reduced even if rates increase?

- Will the impact on certain groups, such as low-income customers, be onerous?

- To what degree will the various stakeholders share in the benefits of a particular DSM program?

- Will the security or the overall cost of operating the utility system create benefits beyond the first round impacts of the DSM program?

- Will the long-term net societal benefits of the DSM program override its immediate rate impacts?

- Are the net societal benefits of such magnitude and importance as to give priority to their attainment?

- Do opportunity costs demand prompt action?

- Will an important DSM program be left undone, or poorly done, if a ratepayer subsidy is not provided?

- Will the inclusion of the DSM program contribute to a broader menu of programs and thereby recognize the needs and perspectives of groups such as low-income customers, Aboriginals and farmers, that might otherwise be precluded from participating?

- Will the inclusion of the DSM program take advantage of synergies among programs?

- The Participant Test should be used as one means of evaluating the appropriateness of a proposed customer contribution.

- A portfolio approach should be employed to allow as many customers as reasonably possible the opportunity to participate and share in the benefits of DSM.

15.1.6 Treatment of Externalities

- The utilities should consider the experiences gained in other jurisdictions, given the scarcity of data on externalities for natural gas DSM in Ontario.

- The significance of an environmental or social externality should be considered qualitatively before deciding whether its effect and impact should be measured.

- Monetization should not be attempted without first measuring the magnitude of the effect of the externality.

- When new studies on externalities and their monetization are required, the utilities should use judgement and recognize the dangers of "paralysis by analysis".

- Externality studies should not unduly usurp resources or delay the timetable for the initiation of DSM programs that can proceed in the absence of such studies.

- When monetizing externalities, avoided costs should be determined by the Cost-of-Control method until the Damage Costing method is further developed.

- The dollar values of monetized externalities should be treated in the same manner as market-determined costs, for planning purposes.

- At least in the near term, sensitivity analyses should be conducted for each monetized externality value.

- The utilities should cooperate when monitoring advances in Damage Costing in other jurisdictions.

15.1.7 Consultation on Externalities

- The utilities should employ a consultative approach toward the identification, measurement and, if possible, monetization of externalities.

- While the utilities are expected to give serious consideration to the views and proposals of the participants in the collaborative process, each utility will remain accountable for its entire DSM plan, including the proposed treatment of externalities.

- The utilities should form a joint Collaborative, which is constituted to:

  - assure that there is representation of the major diverse interests that will be affected;

  - avoid duplicative representation of these interests;

  - be constrained to a manageable number of participants;

- not be bound or limited to the parties in the E.B.O. 169 proceedings;

- provide participant funding in line with the Board's Cost Awards Guidelines;

- consider honoraria to compensate a participant for the value of the time of its employees and officers;

- employ an independent facilitator if this is deemed advisable; and

- utilize the services of experts retained on behalf of the group as a whole, rather than underwriting the costs of a number of experts representing the individual participants.

• The Collaborative should undertake, but not be limited to, the following tasks:

- establish a self-defined mandate, work plan, budget and timetable;

- identify the Cost-of-Control values being used in the SCT in other jurisdictions and, if possible, recommend pertinent Cost-of-Control standards for use in Ontario;

- identify how non-regulated externalities (e.g. CO_2) are being valued in other jurisdictions and recommend how they should be dealt with and, if possible, valued in Ontario;

- identify pertinent externalities that are not currently included in the SCT in other jurisdictions but which should be considered in Ontario and recommend their treatment and, if possible, their valuation;

- review the qualitative assessment methodologies employed in other jurisdictions and recommend approaches to be used in the DSM planning process in Ontario; and

- identify if and where there is a need to consider the unique characteristics of each utility.

- The Collaborative should, as part of its work plan, provide a preliminary report to the Board, and the parties to the E.B.O. 169-III proceeding, describing its agreed-upon mandate, composition, work plan, budget, consultant support and timetable. This initial report should, if possible, be scheduled to issue by September 30, 1993.

- The Collaborative should strive to issue its final report by February 28, 1994.

- In the event that the above deadlines are found to be unrealistic, the Board expects the utilities to make this known as soon as possible and, when doing so, to define the causes of delay and to jointly commit to a revised timetable.

- The utilities should prepare a description and assessment of the process used in the Collaborative and file this with the Collaborative's final report.

- The utilities should propose and justify the recovery of their share of the reasonably incurred costs of the collaborative approach as a component of their costs of service at subsequent rates hearings.

- The consultative approach to resolving DSM matters should be extended beyond the issues of externalities and qualitative assessment methodologies. The choice of how consultation on other issues will be achieved is left to the utilities to decide and justify.

15.1.8 Regulatory Treatment of DSM Investments

- To the degree possible, there should be consistency in the regulatory treatment of supply-side and DSM costs.

- The eligible costs of long-term DSM programs (i.e. those with a duration of more than one year), including "hardware", longer-term incentive rebates and loans, labour, overhead and administrative costs, should be proposed for inclusion in rate base.

- Eligible short-term costs expended over a period of one year or less should be proposed to be expensed and recovered through the cost of service in the year incurred.

- Reasonable broad-based information efforts and associated programs should be proposed as legitimate costs of service without necessarily identifying specific benefits that will be obtained, so long as prudence can be established.

- Information and associated programs that are specific to a DSM program should be accounted as a cost of that program.

- The utilities should cooperate in and, to the extent possible, co-ordinate their broad-based information and associated programs.

- The differences between actual and forecast DSM operating costs and, if necessary, capital expenditures should be proposed to be accrued in deferral or balancing accounts that, together with carrying costs, are to be disposed of at the utility's next rates case, or as directed by the Board.

- NGV programs should be kept separate and not incorporated into the portfolio of DSM programs.

- DSM efforts should be included as part of utility operations and not "spun-off" as a non-regulated affiliated business.

15.1.9 Allocation of DSM Costs

- To the extent possible, the direct beneficiaries of a DSM program should bear the direct financial burden of the program.

- Customer incentives, for purposes such as increasing penetration rates, may be considered when the utility is prepared to justify them.

- The utility should be wary of requiring customer contributions at levels that would restrict participation by groups such as low-income customers, or would induce conversions to less environmentally desirable fuels.

- So long as it does not reach undue proportions, some level of cross-subsidization for DSM programs may be proposed for recovery in rates.

- Rate impacts due to DSM programs should be treated consistently with the rate impacts from supply-side programs.

- While some level of cross-subsidization and rate impact may be acceptable, the utility should make every effort to work toward developing self-sustaining programs.

- DSM programs designed for large commercial and industrial customers should be identified separately from those directed toward small gas users.

- The utilities should disaggregate DSM plans to recognize peak, seasonal and annual cost impacts for the allocation of demand and commodity charges.

15.1.10 <u>Incentives and Decoupling Mechanisms</u>

- If a utility can establish that shareholder incentives are necessary in order to implement DSM programs effectively, it should apply for such incentives when it presents its DSM plan at a rates case and, at that time, also address the need for penalties to be imposed when performance is below expectations.

- If utility incentives are shown to be required, shared savings, based on the nature or urgency of the program, the market being targeted and the degree of difficulty in program implementation, should be viewed as the preferred approach to the provision of incentives.

- If shareholder incentives are proposed, on a program or portfolio basis, the level of the shareholders' portion of the savings should be determined on a case-by-case basis.

- Full decoupling should be viewed as an inappropriate mechanism for use in Ontario at this time.

- If a utility considers that a lack of revenue protection is a significant disincentive, it may propose a revenue adjustment mechanism, provided that the impacts that the mechanism has on the utility's risk exposure and earnings are also considered.

15.1.11

Monitoring and Evaluation

- The utilities should recognize the need to design effective monitoring and evaluation mechanisms into their DSM programs, in order to evaluate a program's on-going cost effectiveness and success, as well as any need for changes.

- When monitoring and evaluating a DSM portfolio, the utilities should provide assurance that the portfolio is fulfilling its expectations with regard to such matters as:

  - the breadth of coverage;
  - the effective use of information and education programs;
  - cost effectiveness;
  - achievement of intended objectives;
  - overcoming anticipated or emerging market barriers; and
  - the capture of potentially lost opportunities.

- The utilities should file base case forecasts of natural gas demand that would be expected in the absence of formal DSM plans.

- Initially, the base case forecast should include the impacts of NGV programs and of DSM programs initiated prior to fiscal 1995, together with the assumptions and price expectations underlying the forecast.

- The DSM plan and program forecasts should be based on achievable potential, derived to the extent possible from end-use models.

- The utilities should report on the degree to which end-use models can be integrated into their forecasts, at the rates case when they file their first DSM plans. The reports should also include the cost, data and time requirements for the implementation of end-use forecasting.

- Forecasts of the costs of programs and plans should be provided on both a total cost and unit cost (per unit of demand and/or savings) basis.

- For each program and for the overall portfolio, forecasts of the pessimistic, optimistic and most likely impacts on the base case forecast should be presented, along with a description of the major assumptions employed.

- Program performance forecasts should describe expected results in each of the first five years of the program and at five-year increments thereafter to the twentieth year of the plan, or the life of the program.

- Each utility should submit an overview of its DSM plan that describes:

    - the goals of its DSM portfolio and how these will be achieved;

    - the objectives for resource planning and customer service;

    - specific DSM savings objectives by class of customer; and

    - a discussion of the alternative implementation strategies considered.

- The utilities should cooperate in their use of pilot programs and in the development of standard monitoring and evaluation techniques.

15.1.12 Rate Design and DSM

- When developing DSM plans, the need for just, reasonable, stable, cost-related rates should be recognized.

- The potential for rate shock should be anticipated and avoided whenever possible.

- While there appears to be little current justification for revising rate structures, the utilities should explicitly consider energy efficiency impacts resulting from rates and rate structures in any future review of rate design.

- The utilities should undertake, and periodically update, assessments of the impacts of interruptible rates, since in addition to constraining system costs, such rates can affect the use of alternate fuels.

- More explicit billing information (e.g. displays of consumption patterns, as well as capacity, customer and commodity charges) should be provided to customers.

15.1.13 Jurisdictional Concerns

- The utilities should not delay or limit the development of their DSM plans pending a resolution of jurisdictional issues.

- DSM plans that extend beyond a given test year should be prepared under the assumption that, once their consequences are approved by the Board, panels in future proceedings will be sensitive to the need for consistency in the treatment of prudent long-term DSM plans.

- When funding is required for effective consultation, the utilities should directly provide such funding in the expectation that prudent expenditures will be recoverable in rates.

15.1.14 Implementation of DSM

- The utilities should present DSM plans in their filings no later than for their fiscal 1995 rates cases. Should this be onerous, a utility should request, as soon as possible, an extension of the timetable.

- The utilities should bring forward evidence on the development, implementation, monitoring and evaluation of DSM programs, portfolios and plans for review by the Board in the context of rates cases, rather than in parallel hearings.

- The utilities should consult with appropriate parties in an effective manner to obtain meaningful input related to each of the major steps in the DSM planning process.

- The utilities should report, when filing a DSM plan, on the planning process, including the consultative process, used to develop that plan.

- The utilities should take advantage of DSM delivery mechanisms, such as those available from ESCOs, rather than competing with, or supplanting them.

- Cooperation with ESCOs should extend to expanding their involvement with both the large and small user groups.

- Where appropriate, programs should be designed to consider all energy conservation opportunities, rather than just focussing on natural gas conservation measures in isolation.

- The utilities should cooperate with organizations such as Ontario Hydro and the municipal electric utilities to implement broad-based conservation programs.

15.1.15 The Board is aware that gas IRP is in its infancy across North America. As a result, the Board anticipates that the initial DSM plans and forecasts may require adjustments as experience is gained during their implementation. The Board feels it is appropriate to learn by doing, rather than wait until a higher level of certainty is achieved. Thus, while the Board will expect the utilities to commit to their DSM plans, and to work diligently toward their achievement, the plans should allow for the flexibility to make mid-course corrections and adjustments when necessary.

16. COST AWARDS

16.0.1 Section 28 of the Act states in part:

> (1) The costs of and incidental to any proceeding before the Board are in its discretion and may be fixed in any case at a sum certain or may be taxed.
>
> (2) The Board may order by whom and to whom any costs are to be paid and by whom they are to be taxed and allowed.
>
> (3) The Board may prescribe a scale under which such costs shall be taxed.
>
> (4) In this section, the costs may include the costs of the Board, regard being had to the time and expenses of the Board.

16.0.2 In addition to the Board's discretion to award costs, the IFP Act requires the Board to consider applications for intervenor funding in advance of a hearing. An intervenor funding hearing is held to determine if a funding request should be granted, modified or denied. The Board's funding decision also identifies a funding proponent, who is directed to pay any advance award. Any funds awarded under the IFP Act must by statute be deducted from any subsequent cost award ordered by the Board.

16.1 Phase I Cost Awards

16.1.1 On May 10, 1992 the Board issued a letter to all parties to the E.B.O. 169 proceedings wherein, inter alia, the Board announced that, since these proceedings were likely to be protracted, the Board would consider interim cost awards to alleviate the financial burdens that might otherwise be imposed upon the parties.

16.1.2 On May 26, 1992 the Board issued Procedural Order E.B.O. 169 No. 2, which invited parties to apply for an interim award of costs that were reasonably incurred to the date of that order (i.e. Phase I), due to their participation in the E.B.O. 169 proceeding. By that Order the Board further instructed those parties applying for an interim award of costs to submit a cost statement and to file an accounting of their use of the funds awarded by the Board's E.B.O. 169 Funding Decision (for Phase I) dated December 20, 1991.

16.1.3 By Procedural Order E.B.O. 169 No. 2, the Board also allowed that those parties that had been active in Phase I and expected to participate in future phases of the E.B.O. 169 proceedings might apply to recover their costs related to Phase I when the Board considers future applications for cost awards in these proceedings.

16.1.4 On August 14, 1992 the Board issued its Decision with Reasons which awarded 100 percent of their reasonably incurred costs for Phase I to all applicants. The last of the Board's E.B.O. 169 Phase I Cost Orders was subsequently issued on November 26, 1992. The table which follows lists the parties that were awarded costs and/or advance intervenor funding for Phase I.

E.B.O. 169 Phase I Awards		
Party	**Intervenor Funding $**	**Cost Award $**
CAC(O)	52,748	37,516
CAESCO	17,403	30,443
The Coalition	78,462	73,365
Energy Probe	77,690	81,497
OMAA	66,835	Deferred
Pollution Probe	15,630	15,680
City of Toronto	N/A	5,049
N/A Did not apply		

16.2 PHASE II COST AWARDS

16.2.1 On October 9, 1992 the Board issued Procedural Order E.B.O. 169-III No. 2, which invited the parties to submit applications for costs incurred between May 27, 1992 and October 9, 1992 inclusive (i.e. Phase II), as a result of their participation in the IRP proceedings. As previously allowed in Procedural Order E.B.O. 169 No. 2, parties that had deferred applying for costs incurred in Phase I were also eligible to apply to recover these costs. Parties that expected to continue to participate in future phases of the IRP proceedings were again given the option to apply to recover their Phase I and/or Phase II costs on a future occasion.

16.2.2 In its E.B.O. 169 Interim Costs - Phase II Decision with Reasons, issued on January 15, 1993, the Board dealt with the applications for costs that were filed pursuant to Procedural Order E.B.O. 169-III No. 2. The Board awarded 100 percent of the reasonably incurred costs of the parties that then applied for costs. The advance intervenor funding and cost awards authorized at the end of Phase II are shown on the table which follows.

E.B.O. 169 Phase II Awards		
Party	**Intervenor Funding $**	**Cost Award $**
AMPCO	N/A	$13,148*
CAC(O)	22,756	Deferred
CAESCO	28,942	47,221
The Coalition	29,822	39,814
Energy Probe	24,628	21,471
IGUA	N/A	9,098*
City of Kitchener	N/A	11,774
MEA	N/A	4,205
OMAA	27,297	119,131
Pollution Probe	24,941	29,969
City of Toronto	N/A	6,372

N/A Did not apply
* combined award for Phases I and II

16.3 PHASE III COST AWARDS

16.3.1 On December 4, 1992 the Board gave oral directions to the parties regarding applications for cost awards subsequent to the close of the evidentiary phase of the E.B.O. 169-III hearing. These directions were further contained in Procedural Order E.B.O. 169-III No. 4, which was issued on December 7, 1992.

16.3.2 In that Procedural Order the Board required as follows:

- Applications for cost awards for Phase III, and for deferred awards for outstanding costs incurred in Phases I and II, shall be made at the time of submitting argument-in-chief in the Phase III hearing.

- Objections to an award of costs to other parties shall be made at the time of reply argument, and replies to any such objections shall be filed on or before February 1, 1993.

- Applicants for cost awards shall file their statements of costs on or before February 8, 1993, and use the forms appended to the Procedural Order.

- Accountings of the use of any unreconciled funds awarded in the E.B.O. 169 proceedings pursuant to the Intervenor Funding Project Act shall be filed on or before February 8, 1993, and shall be segregated to separately account for the use of funds awarded in each phase of the E.B.O. 169 proceedings.

- There shall be no further carry-forward allowance for funding or costs incurred in Phases I, II or III of the E.B.O. 169 proceedings. All accounts will be closed to additional entries after the receipt of submissions filed up to and including February 8, 1993.

16.3.3 The intervenor funding awards and the cost claims for Phase III are shown in the table which follows.

E.B.O. 169 Phase III Awards and Claims		
Party	**Intervenor Funding Award $**	**Cost Claim $**
CAC(O) Phase II Phase III II & III Combined	22,756 26,508 49,264	29,549* 64,757 94,306
CAESCO	N/A	39,448
The Coalition	36,119	59,288
Energy Probe	51,197	111,833
City of Kitchener	N/A	38,392
OMAA	22,785	24,715
Pollution Probe	22,940	56,873
The Farm Association	Denied	14,111
City of Toronto	N/A	7,851

N/A Did not apply
* Deferred from Phase II to Phase III

16.3.4 In its reply argument, Consumers Gas noted that the City of Kitchener had described its interest in the IRP proceedings as being that of a utility and as a customer of Union. Consumers Gas submitted that, as a storage and transportation service customer of Union, the City of Kitchener, as a utility, was not substantially distinguishable from Centra and Consumers Gas. Further, Consumers Gas maintained that it would be inappropriate for the ratepayers of Union, Centra and Consumers Gas to subsidize an intervention put forward by the City of Kitchener as a utility. Consumers Gas, therefore, argued that it would be inappropriate for the Board to award costs to the City of Kitchener. The City of Kitchener did not reply to the objection by Consumers Gas.

16.4 BOARD FINDINGS

16.4.1 In its E.B.O. 116 Report the Board listed the considerations that generally will be taken into account when awarding costs. The three major considerations are that the intervenor:

> has or represents a substantial interest in the outcome of the proceeding of such a nature that the intervenor will receive a benefit or suffer a detriment as a result of the order or decision resulting from the proceeding;
>
> has participated in the proceeding in a responsible way; and
>
> has contributed to a better understanding of the issues by the Board.

16.4.2 When making its findings regarding the awards of costs in this proceeding the Board was guided by these considerations.

16.4.3 The Board has taken note of the conduct of each intervenor during the hearing, and has considered the quality of the testimony and written evidence presented. The Board has also taken into account the substance of the arguments filed by each party when deciding its award of costs.

16.4.4 The Board notes the objection filed by Consumers Gas with regard to an award of costs to the City of Kitchener. The Board does not accept Consumers Gas' submission that the City of Kitchener is indistinguishable from Consumers Gas or Centra on the basis that, as customers, they purchase the same type of service from Union. Nor does the Board accept the contention that the City of Kitchener is a "utility" on an equal footing with the three large gas distributors in Ontario. The Board has no difficulty distinguishing between the City of Kitchener and Consumers Gas, Union or Centra. Given that a pass-through of Union's IRP-related costs can have a significant impact on the City of Kitchener's costs, the Board finds that the City of Kitchener meets the test of the first of the E.B.O. 116 considerations set out above, and is, on that basis, eligible to be considered for a cost award.

16.4.5 With regard to the conduct of the parties at the hearing, the Board finds that all the witnesses and counsel acted responsibly in presenting their evidence and in cross-examination. The Board appreciates the cooperation and assistance that the parties provided in order to expedite this technically and administratively complex proceeding.

16.4.6 With regard to the substance of the interventions, the Board finds that each of the active parties in the Phase III hearing contributed to the Board's understanding of the difficult issues that were before the Board.

16.4.7 The Board recognizes that the Phase III hearing was the culmination of efforts that included work done over a period of more than a year in Phases I and II. The Board, therefore, will not segregate and focus in isolation on the contributions that were made by the parties in only the Phase III hearing.

16.4.8 The Board finds that 100 percent of their reasonably incurred costs applied for at the end of Phase III of the E.B.O. 169 proceeding shall be awarded, subject to review by the Board's Assessment Officer, to the following intervenors:

- CAC(O) (for both Phase II and Phase III)
- CAESCO

- The Coalition
- Energy Probe
- The City of Kitchener
- OMAA
- Pollution Probe
- The Farm Association
- The City of Toronto

16.4.9 In compliance with section 12 of the IFP Act, the Board directs that the amount of intervenor funding that was awarded to an intervenor for Phase III shall be deducted from the corresponding award of costs in Phase III of these proceedings. In the case of CAC(O), the total funding awarded under the IFP Act for Phases II and III shall be deducted from the amount awarded herein. In the event that the total amount funded to an intervenor for the entire E.B.O. 169 proceeding exceeds the total amount awarded for its costs in the proceedings, any outstanding difference shall be repaid, forthwith upon receipt of the Board's Phase III cost order, to the funding proponents in the same proportion as their funding payments.

16.4.10 As has been the practice in all previous phases of these proceedings, the Board directs that, subsequent to their review by the Board's Assessment Officer, the costs awarded herein shall be paid, forthwith upon receipt of the Board's costs orders, by Consumers Gas, Union and Centra in the following proportions:

Consumers Gas shall pay 3/6
Union shall pay 2/6
Centra shall pay 1/6.

16.4.11 The Board further finds that Consumers Gas, Union and Centra shall pay, in the proportions set out above, the Board's costs of and incidental to Phase III of these proceedings forthwith upon receipt of the Board's cost order and invoice.

Dated at Toronto July 23, 1993.

Marie C. Rounding

Marie C. Rounding
Chair and Presiding Member

Carl A. Wolf Jr.

Carl A. Wolf Jr.
Member

Judith C. Allan
Member

Judy Simon

Judith B. Simon
Member

APPENDIX A

EXECUTIVE SUMMARIES AS SUBMITTED BY THE PARTIES

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* No Post-hearing submissions filed

APPENDIX A

EXECUTIVE SUMMARIES AS SUBMITTED BY THE PARTIES

EXECUTIVE SUMMARY OF BOARD STAFF

INTRODUCTION

Board Staff submits that the goal of IRP is to place DSM initiatives on an equal footing with supply-side resources as a means of meeting customer needs. DSM initiatives, for the purposes of this proceeding, are energy efficiency and conservation measures, and therefore do not include fuel substitution programs. Board Staff agrees with CAC(O) that the goal of DSM should be the development of effective and cost-effective programs that maximize savings or net societal benefits while minimizing the cost requirements of securing those benefits, both in the short term and the long term.

Wherever possible, demand-side options should be treated consistently with supply-side options. Board Staff submits that the Board should adopt the NARUC resolution which calls for the reform of regulation in order to make the successful implementation of a utility's least-cost plan its most profitable course of action.

There is a concern that DSM will cause rates to increase unnecessarily. The Board must ensure that cost-effective DSM options are used as resources; that is, used to replace supply resources. In no circumstances should the utilities be permitted to implement DSM programs if they have no provable intention of reducing supply-side resources. The rate impact of DSM must never be greater than the rate impact that would have resulted from the alternative supply option, and in all cases the utilities and the Board should try to keep it lower. The Board must not allow undue cross-subsidization between existing and new customers or between rate classes. Ultimately, the effect of DSM on rates for natural gas users will depend on how aggressive the Board wishes the implementation of DSM plans and portfolios to be, and how it evaluates these against supply options.

ISSUE 1

The use of avoided supply-side costs is the appropriate measure of benefits attributable to DSM programs. Components of avoided supply-side costs include capital, operating and energy costs, as well as externalities. There is a need for flexibility in the determination of actual avoided costs, as these costs must reflect both the timing and system differences which may be specific to each DSM program and unique to each utility. The Board should indicate which avoided costs it considers appropriate.

It is submitted that avoided costs provide a direct comparison to supply-side options. Avoided costs can be direct inputs into the cost-effectiveness tests, thereby allowing the utilities to evaluate the DSM programs. Further, the avoided cost methodology is consistent with the determination of costs and benefits outlined in E.B.O. 134 which allows for both quantitative and qualitative consideration of externalities on the supply-side evaluation. Public interest factors should be weighted consistently when evaluating demand and supply options.

Board Staff supports the inclusion of externalities as an avoided cost. The treatment of externalities in supply-side cases under E.B.O. 134 provides a guide to the utilities. Board Staff points out, however, that only positive externalities (those that increase the benefits of a project) have been included to date on supply-side projects. Externalities have not been accounted for as a cost on the supply-side.

Dr. Lerner for Union suggested that, in comparison to avoided supply costs for electricity, the avoided costs for the gas utilities will be lower and the justification of large numbers of new DSM programs will be difficult. Mr. Edgar for CAC(O) stated that "...in some cases the avoided costs for some gas utilities would be lower than the avoided costs for other utilities. It would really depend on the growth in their area." Board Staff believes that Dr. Lerner's and Mr. Edgar's points have merit especially in the determination of avoided facilities and operations costs in mature market areas. Board Staff submits that, given the variability in avoided costs among the utilities, it is necessary that DSM program monitoring and evaluation include an ongoing comparison of forecast and actual avoided costs. Without this monitoring, the Board will not have any accurate data on the costs actually avoided. Board Staff submits that the Board should direct the utilities to present a monitoring system for avoided costs with their proposed DSM programs.

Board Staff submits that in order to truly compare DSM programs on an equal footing with supply-side options, the Board should support the inclusion of long-run avoided costs, equivalent to those presently used in establishing the economic feasibility of the supply-side options.

To the extent that DSM programs reduce demand by a given increment, that increment will be reflected in upstream production and transmission systems. Therefore, the Board should direct the utilities to prepare studies of their avoided costs, with and without the avoided costs upstream of their own systems. The Board may wish to recommend that it be given provincial approval to request the National Energy Board to require TCPL to estimate these costs. The avoided costs of Union's transmission system are somewhat easier for the Board to obtain. Another avoided cost to consider is avoidance of unabsorbed demand charges.

Where DSM measures reduce reliance on supply-side requirements, the avoided cost must be considered a direct benefit attributable to DSM. Board Staff recommends that the Board require that the utilities identify the adjustments to the supply-side plans that they attribute to DSM programs. The utilities should file the expected DSM savings under different scenarios (low, medium and high savings) and the corresponding impact on supply-side plans. DSM options can only be successful when inclusion of DSM results in demand forecasting achieves a reduction in the supply-side requirements.

ISSUE 2

Board Staff supports the Consensus Statement on cost-effectiveness tests because the criteria take into account a broad range of public interest factors and protect against an undue burden being placed on existing customers. Board Staff submits that the portfolio approach is the most effective means of ensuring that a broad range of DSM programs are offered to all classes of customers. It allows low income groups, renters and tenants to participate in these programs. It also keeps the burden on existing customers in check.

Board Staff submits that the DSM portfolio should not be required to pass the RIM test, but that it should place no undue burden on any customer or customer class. The Board has traditionally endorsed rates that are cost-related rather than strictly cost-based, and has also approved financially non-sustaining distribution and transmission projects for public interest reasons. It is therefore submitted that some level of rate impact arising from the DSM portfolio is acceptable. However, in no circumstances should this rate impact be greater than the rate impact that would have resulted from the alternative supply option; in all cases, the Board and the utilities should try to keep it lower.

Board Staff submits that examination of the portfolio of DSM programs in a rate case may not provide sufficiently detailed information to determine the efficiency and effectiveness of individual DSM programs. The Board should direct specific filing protocols which address DSM program avoided cost analysis, demand forecast impacts and actual impacts of existing programs on an individual program basis.

Board Staff submits that there are significant differences between the regulated monopoly environment in which supply-side activities of the utilities are undertaken and the competitive environment in which the utilities will operate demand-side activities. If the utilities are to offer DSM goods and services that will compete with major commercial distributors, they will have to be at a lower price than that currently available in the market place, or the utilities will have to differentiate their product or service.

Board Staff submits that contributions from DSM program participants should be used to maximize the cost-effectiveness of all programs. The same effort should apply to contributions in aid of construction. Board Staff's primary concern is with maintaining reasonable rates for existing gas consumers. To maintain a positive balance in a portfolio of DSM projects, the utilities will have to undertake numerous cost-effective programs. The need for test marketing and pilot programs in areas where the utilities will be in direct competition with other commercial suppliers is critical. Board Staff submits that the Board as part of its report should emphasize the need for the utilities to establish a market response to their new DSM programs before franchise-wide implementation.

The Board must address the issue of the appropriate cost-effectiveness tests and screens, as well as which avoided costs should be included. The Board should indicate whether the utilities should apply the demand-side cost-effectiveness test in a consistent manner with the application of E.B.O. 134 tests for new capital expenditures.

ISSUE 3

The environmental and social impacts of gas usage are a real cost to society which has not been reflected in the price of gas usage to date. All the parties agreed that externality impacts should be included in establishing the feasibility of DSM programs. Board Staff submits that there should be consistent treatment of externalities among the utilities. As there is difficulty in monetizing values for individual externalities and in establishing the range of externalities to be considered in the cost-effectiveness of DSM programs, the working group proposal has been endorsed by all three utilities. Board Staff submits that it may not be necessary to monetize all or even many externalities before the utilities could ensure that a particular program passes the Societal Cost Test.

In Board Staff's submission, the Consensus Statement on Issue 3 provides the utilities with sufficient direction on the treatment of externalities, as it provides the framework for consideration of all identifiable externalities (societal and environmental) in both a qualitative and quantitative sense. Board Staff supports the Consensus because it recognizes externalities on an equal footing with other costs and benefits in cost-effectiveness testing. The Board has already recognized externalities as part of the quantifiable and non-quantifiable public interest factors considered in cases under E.B.O. 134. It is further submitted that, should the Board so desire, the framework for demand-side options can be used to refine or supplement the E.B.O. 134 framework. The use of sensitivity analysis would provide a range of values for externalities which could be applied as part of the Societal Cost Test.

The proposed working group is a means of ensuring that the monetization of externalities is done in a consistent manner amongst the utilities and with input from interested parties. Board Staff submits that the Board should approve the working group approach with the terms of reference as outlined by Centra Gas and CAC(O). The Board should also recommend how the utilities should evaluate those externalities that cannot be quantified. The Board should also establish a time frame, such as six months, within which the working group should report its findings to the Board. Should the Board endorse the working group, funding would be required for interested parties to participate effectively. Board Staff submits that participation from interested parties is essential to developing monetized values for externalities which will have the support of those parties during future proceedings.

ISSUE 4

The utilities have legitimate concerns regarding DSM program costs and their timely recovery. The underlying considerations in the Consensus Statement on Issue 4 include the importance of consistent treatment between demand-side and supply-side options, the ease of application and regulatory review, and an amortization period for DSM expenditures which is equitable in matching costs and benefits. If regulatory practices present utility planners with disparate financial risks and rewards for different resources, then resource selection will be biased in favour of options that are either more profitable or less risky. Spreading the costs over the lifetime of technologies, or the period of the benefits to be realized, reduces negative rate impacts in the earlier years of a program. Board Staff submits that the Board should endorse the consensus for the reasons stated above.

The main difference in accounting treatment for DSM expenditures compared to supply-side expenditures is that the utilities are looking for further reassurance that they will be able to recoup all of the costs incurred. As many DSM programs are of longer duration than one year, the utilities require approval for multi-year plans. Therefore, the utilities should establish a deferral account for DSM operating/capital expenditures, in order to alleviate the uncertainties surrounding DSM expenses, particularly in the early stages of new programs. The utility would be able to recoup all DSM costs incurred for program implementation and would have greater flexibility to respond to a program's success or failure.

Board Staff submits that the use of a deferral account in the early years of DSM implementation will prevent the utility from abandoning a program once the budgeted funds run out, which would result in lost opportunities, as well as mixed signals to the public. The balancing account has the additional advantage of lowering the utility's new risk with respect to investing in non-revenue generating assets. The deferral account would be examined at the next rate case proceeding to test the prudency of the expenditures. The deferral account has primary significance in the earlier years of DSM implementation. At each rate case, the necessity for the deferral account would be addressed.
The Board must describe how it intends to treat the DSM expenditures and whether it will allow the use of a DSM deferral account. Guidelines are necessary on how costs are to be amortized and recovered. The Board must also define what kinds of programs are eligible for inclusion in the DSM portfolio.

ISSUE 5

Participants who are the direct beneficiaries of a DSM program should bear, to the extent possible, the direct financial burden of the program. The remaining costs of the programs should be allocated to all existing gas customers on a system-wide basis.

Effective program design helps to minimize the costs and maximize the benefits of DSM. Board Staff submits that providing incentives to customers will encourage participation in DSM programs, improve the cost-effectiveness of programs and may increase the net social benefits. Incentives will also help target special customer groups that might not otherwise participate in DSM programs. Higher participation rates improve the financial performance of a DSM program, but the incentives should not be so high that they impair the cost-effectiveness of the program, or that the utilities simply give away DSM options.

Board Staff submits that customer contributions are appropriate for DSM programs, as they could make financially non-sustaining DSM programs more profitable, thereby reducing the subsidy from non-participants. Contributions should be as high as possible without deterring participation. To be consistent, contributions should also be sought for financially non-sustaining fuel switching programs or other supply-side projects, which are endorsed by E.B.O. 134 provided the social benefits exceed the costs. Wherever possible, the utility should strive to have the measure pass the RIM test or have a benefit/cost ratio of one.

Demand-side and supply-side costs should be treated consistently for cost allocation purposes. The allocation of DSM program costs not recovered from program participants should recognize and be proportional to the distribution of program benefits. Board Staff submits that it is appropriate to extend some portion of DSM costs to the system as a whole, as all ratepayers will benefit from the avoided costs of future supply and the avoidance of externalities.

Board Staff submits that the utilities should be directed to start their research on cost causality of DSM programs, and that they should share the costs of such research to the extent practical. The utilities should also be directed to work with the ESCOs, which may have valuable input regarding cost causality to share with the utilities for the commercial/industrial and institutional sectors.

Board Staff submits that the Board should approve the Consensus Statement on Issue 5(a). This would not require the DSM portfolio to pass the RIM test, as there may be some justified upward impact on rates. The Board has traditionally endorsed rates that are cost-related rather than strictly cost-based, as long as the resulting rates do not place an undue burden on any customer or customer class. The Board has also approved financially non-sustaining distribution and transmission projects for public interest reasons. It is therefore submitted that some level of rate impact is acceptable, but in no circumstances should it be greater than the rate impact that would have resulted from the alternative supply option.

Board Staff submits that while some degree of cross-subsidization is unavoidable, there should be some attempt to limit it to reasonable levels. The appropriate level of subsidy would be at the utility's and the Board's discretion, consistent with the manner in which the Board currently evaluates supply-side options. The diversity and widespread application of DSM programs across all customer classes would help ensure overall equity, as there would be relatively few non-participants. The Consensus Statement addresses the issue of intra-class subsidization by supporting customer contributions to DSM programs. The balance is in finding the appropriate level of customer contribution or incentive to ensure that the benefits are produced, but trying to reduce the amount of incentives in order to prevent intra-class and inter-class subsidies.

ISSUE 6

Board Staff submits that shareholder incentives should be made available to the utilities to undertake DSM programs to remove any disincentive to the aggressive implementation of cost-effective DSM programs. Board Staff submits that incentives are necessary to make the utility choose to implement DSM initiatives where they replace supply-side resources. Supply options generate revenue and a return on rate base; it is therefore submitted that DSM options should be made equally attractive to utility management. Financial incentive mechanisms should not only remove disincentives to DSM, but should also encourage positive action and align utility management objectives with those of societal objectives. Incentives must be earned, based on measured cost-effective savings rather than on the level of DSM expenditures. An added benefit of a shared savings plan is that it may help mitigate the short-term risk associated with undertaking DSM programs. Board Staff submits that the Board has the authority to implement a shared-savings mechanism. The Board should support the Consensus Statement on Issue 6, Part 1. If incentives are not available to utility shareholders, the Board must address how it intends to ensure that a sufficient amount of cost-effective DSM will be implemented by the utilities.

Board Staff submits that the use of a penalty mechanism (i.e. the reverse of shared savings, or disallowance of costs) is reasonable in cases where the utility's performance is poor or non-existent. This is to be dealt with at a rate case proceeding. The Board should also state whether it finds the use of penalties for poor performance to be appropriate.

Parties agreed that there is an inherent bias in the present rate-making system which provides an incentive to the utility to sell more gas than forecast during the rate year. Decoupling makes the utility indifferent to the level of gas sales during the period between rate cases. Board Staff submits that the Board should implement decoupling for all three utilities in Ontario. However, if the Board is not prepared to mandate decoupling for Centra and Union at this time, then full decoupling should at the very least be implemented for Consumers on a trial basis. Board Staff submits that the Board has the legal authority to implement a decoupling mechanism if it decides that one is in the public interest. If the Board perceives that decoupling will have public interest benefits, the Board need not have the utilities' consent for instituting appropriate policies. If decoupling is not adopted, the Board must indicate how the utilities are to recoup lost revenues.

Board Staff agrees that decoupling is not **necessary** for the implementation of successful DSM programs. The decision to implement decoupling or not must be based on how much the Board wants the utilities to achieve with respect to energy efficiency and conservation. Decoupling helps to break utility managers' preference for growth in sales and rate base. For this reason alone, it is submitted that decoupling may be appropriate for utilities with a focus on load building.

It is submitted that decoupling separates a utility's profitability from sales volume, and consequently, removes the disincentive to pursue energy efficiency as well as removing the incentive to increase sales in the rate year. Board Staff submits that the utility must be indifferent to the level of sales in order to place DSM options on an equal footing with supply options. Further, if the utility is protected from net revenue losses, then symmetry requires that the rate payers be protected from net revenue gains that would occur if the utility undertook less DSM than anticipated in the test year. Decoupling would provide this symmetry.

Lost revenue adjustment mechanisms may allow the utility to recoup additional revenue from ratepayers regardless of whether the utility is earning more than its allowed return. In addition, a lost revenue adjustment account will not take away the utility's perceived advantage associated with increased sales. This kind of account cannot capture the effects of informational DSM programs, and potentially other programs as well. There will also be considerable difficulty in estimating what the lost revenues are, giving rise to greater regulatory complexity than decoupling. Nor does this mechanism neutralize the incentive to sell more gas than forecast between rate cases.

Decoupling makes the utility neutral to sales promotion. Combining decoupling with deferred accounting for program costs will make the utility neutral to conservation and opposed to sales promotion. Board Staff submits that there are other incentives present for promotional costs, such as the incentive of rate base, the desire to satisfy customer needs, and the risk of regulatory scrutiny. If the Board wants the utility to promote certain types of sales, it could allow for deferred accounting of sales promotion costs. The advantage is that the Board, not the utility, determines which uses should be promoted, thereby ensuring that the public good is served.

Decoupling reduces volatility of revenues, and shifts the risk of weather and the economy onto rate payers. However, the risk is symmetrical and if the risk transfer is significant, it may be reflected in the cost of capital and the allowed rate of return, which would be a lower cost to the rate payers. It is submitted that this debate is best reserved for a rate case.

Without decoupling, shareholder incentives to make conservation the more profitable option will have to be larger than they would have to be with decoupling. Decoupling also makes it possible to try to mesh rate design with DSM programs, by allowing the utilities to move away from their dependence on fixed customer charges and focus more on commodity charges which are closer to marginal pricing. Decoupling could make the utility indifferent to the activities of ESCOs, allowing them to displace or at least reduce the need for utility involvement.

Board Staff submits that the revenue-per-customer approach on a customer class basis has merit. This methodology would have to be modified to take Centra's concerns regarding industrial customers into consideration. It is submitted that the Board should direct Centra and Union to evaluate some of the suggestions put forth by parties to this proceeding to reduce the variability of revenues.

ISSUE 7

The Consensus for Issue 7 addresses the need for careful research, monitoring and evaluation in order to take into account all of the factors which may affect the cost-effectiveness and net social benefits of each DSM program, while giving the utilities some flexibility of approach.

Board Staff submits that proper program selection is necessary to maximize the achievable potential of DSM. At the same time, there is a trade-off between identifying DSM potential and keeping costs to a reasonable level. As more research, analysis and monitoring are undertaken, the costs rise and the incremental benefits drop. Identifying technical potential is understood to be of limited practicality.

Board Staff submits that the goal of identifying achievable potential provides an explicit framework for developing and evaluating a DSM portfolio. Estimates of the achievable potential and the cost-effectiveness of most programs depend on the assumptions underlying participation rates, therefore some sensitivity analysis should be performed. Board Staff submits that it is necessary to identify the achievable potential, including expected participation levels, of any given program before one can determine the program's cost-effectiveness. Union's proposed method of identifying DSM potential by addressing only known market barriers, carries a high risk of missing less obvious but socially beneficial areas of DSM potential. Board Staff is concerned that Union does not intend to implement DSM beyond its current level.

Free ridership may be a possible obstacle to developing accurate estimates of program potential. Undetected free-ridership means that the actual benefits of a program relative to the costs are lower than they appear. It is submitted that free ridership will not be a serious problem provided that some attempt is made to account for the effect of free riders in assessing program costs and benefits. It is not apparent to Board Staff that increasing program costs by raising the incentive level will necessarily be offset by an equal or greater increase in benefits.

Board Staff submits that energy service companies are a valuable resource which the utilities should be encouraged to utilize. However, the types of programs in which ESCOs are involved differ substantially from those which are most logical for the utilities to adopt. While their expertise is almost certainly transferable to the utilities, the program emphasis and research methods of the ESCOs are not.

It is Board Staff's view that market barriers, and particularly lost opportunity situations, should and will be a primary focus for DSM programs. First-time costs and lack of information are the barriers to customer acceptance of DSM measures on which the LDCs expect to place their primary focus. While overcoming market barriers is important, avoiding lost opportunities is also an important consideration in designing DSM programs, to focus on those opportunities which arise only once or seldom, specifically appliance replacements and new construction.

There is a trade-off between accuracy and cost in choosing the types and extent of monitoring to undertake. Board Staff supports the use of pilot programs for any new or unfamiliar DSM program or which generates a relatively large degree of uncertainty concerning participation rates. Board Staff submits that monitoring and evaluation will ultimately determine the success or failure of DSM programs. There is a serious risk that inadequate evaluation may cause costly DSM programs to remain in place. The Board should direct the utilities to report on monitoring and evaluation mechanisms which will be scrutinized in subsequent rate cases.

ISSUE 8

The Board's traditional approach to rate-setting has been to support cost-related rates, allowing some cross-subsidization to meet qualitative policy objectives. In Board Staff's submission, a new objective in rate design is the explicit consideration of energy efficiency and conservation objectives. Redesigning rates to encourage conservation of gas may have a detrimental effect to the extent that users choose to use competing fuels as a result of increased gas prices at the margin. Rate structure changes must be approached cautiously, because they could create an atmosphere of instability and discontent if poorly designed or implemented too rapidly. Board Staff submits that rate stability should not be considered a problem. It is submitted that in the past, rate restructuring has occurred in such a way that any unavoidable negative impacts were mitigated by implementing the changes gradually. Staff supports the Consensus in setting aside the debate about risk in rate design measures to a future date when there are specific proposals to discuss.

Seasonal pricing is more economically efficient than current average cost pricing, by allocating costs more closely to the people who are imposing higher costs on the system. In theory, marginal cost pricing would also smooth the seasonal load peaks, supporting the goal of conservation as well as economic efficiency. Board Staff submits that there are many options for residential customers to improve the efficiency of their winter gas use, as well as adding summer applications of gas. Although equal billing may somewhat mute price signals, this problem can be substantially mitigated by providing more information to customers.

Board Staff agrees provisionally that inverted rates may be economically inefficient because they discourage socially desirable load-building activities. It should be noted, however, that precise estimates of negative load-building impacts versus conservation benefits would need to take into account the price elasticity of demand at the margin and the cross price elasticity of gas with respect to competing fuels, and the relative environmental impacts of each effect. Board Staff submits that inverted rates are not a practical consideration at this time, as they pose problems for the utility's revenue stability, because most of the cost recovery would occur at the margin. In addition, Board Staff submits that inverted rates would create equity problems even in the relatively homogenous residential sector, by penalizing large families and customers who may use gas efficiently but for more applications.

Board Staff submits that the use of interruptible rates should not be altered at present to try to further the goals of IRP. It is evident to Board Staff that information on the environmental impacts of interruptions would be helpful. Board Staff submits, however, that interruptible rates can be of great assistance to the utility in avoiding peak demand supply costs. It is therefore submitted that the Board should direct the utilities to track more closely the use of alternative fuels during interruptions.

ISSUE 9

The opinions provided by Ian Blue and Osler, Hoskin & Harcourt (Exhibit 1.11, Appendix D and Exhibit 3.1, Appendix A) outline the extent of the Board's jurisdiction in matters related to IRP and are also applicable to DSM programs. In each case, counsel reaches the conclusion that the Board has the jurisdiction to approve the test year rate making implications of DSM programs and to issue guidelines as to the evaluation of DSM programs.

Board Staff submits that no active party to the proceeding is in disagreement with the Consensus Statement. Rather, Board Staff submits that the lack of unanimity for the consensus statement arises from the issue of whether or not the Board should acquire jurisdiction, through legislative amendments to the Ontario Energy Board Act, to implement a formal IRP process. Board Staff submits that the Board should adopt the Consensus Statement on Issue 9 as being reflective of its jurisdiction in the area of DSM program approval.

ISSUE 10

The Board must indicate how it intends to pursue the implementation of DSM plans, and whether it intends to deal with the remaining issues of IRP (supply-side issues and the integration of demand and supply into a decision-making format). With respect to short-term DSM implementation, Board Staff submits that the Board should indicate its support for a consultative process among the utilities and intervenors, and should set parameters in its DSM guidelines to ensure a productive and efficient consultative process. Board Staff submits that the parameters should be: broadly based representation by interested parties; timing such that the interested parties are included in the process of DSM program development; the consultation structured so that all parties begin the process with an understanding of the content and expected results; and, a report on the consultation process and results included in the evidence supporting the utility's DSM plan at a rate case.

Board Staff submits that the Board should indicate that any costs for undertaking consultations are eligible for inclusion in the utility's cost of service subject to examination in a rate case. Without such funding interested parties will be excluded from the consultations and will be required to rely on intervenor funding and the rate hearing process in order to provide their input into DSM plans. This would be a less productive and probably more expensive outcome. Board Staff submits that the utility should be responsible for the control of these costs. The Board's current cost assessment guidelines represent sensible criteria for the utilities in considering funding requests. Any party which is excluded from the consultation through insufficient funding could still apply for intervenor funding in a rate case. Input from such a party would be one of the factors for the Board to consider as to whether the utility had undertaken its consultations appropriately.

Board Staff submits that the legal basis for the Board itself to award funding in the consultation process is doubtful. The existence of a proceeding and the granting of status to an intervenor are prerequisites to an award of funding to that intervenor under the Intervenor Funding Project Act ("the IFPA"). In order to award funding under the IFPA, the Board would have to find that the consultation process is part of an ongoing IRP proceeding, or that a utility rate case proceeding continued throughout the consultation process. Board Staff does not recommend that the Board make such a finding. The Board also has the power to award costs through section 28 of the OEB Act. Subsection 5 of that section does permit the Board to award costs in the form of advance funding. However, Board Staff submits that the prerequisites of the existence of a proceeding and the granting of status apply with equal force to this section of the OEB Act. Board Staff submits that the most practical and legally sound approach is to allow the utilities to pass through reasonable costs in connection with the consultation process as part of cost of service. If the Board ever determines that the funding is not being appropriately undertaken by the utilities, it could then invoke provisions of the IFPA and assume responsibility for deciding these funding requests.

Pollution Probe has recommended that affiliate gas supply transactions be banned on the basis that if an affiliate is supplying gas to a utility, this will result in a disincentive to the utility to pursue conservation. As an alternative, Mr. Gibbons recommended that all affiliate gas supply contracts should contain a provision whereby the volumes would not be subject to displacement if the utility's requirements are diminished. Board Staff submits that neither recommendation put forward by Pollution Probe is warranted at this time. While the identified disincentive may exist, there is not sufficient evidence on the magnitude of the problem to justify the proposed remedy. Board Staff notes that this disincentive will continue to exist, to the extent it is driven by the utility's parent, whether or not there is a sale between the affiliate and the utility.

With respect to long-term IRP implementation, Board Staff submits that the Board should adopt Parts 1, 2(a) and 2(c) of the Consensus Statement on Issue 10. The Board may wish to indicate whether it will pursue legislative change in the expectation of more extensive implementation of IRP. There are a number of areas in which not enough is known at this time to make specific recommendations for amended legislation. These areas include: whether the Board accepts the definition of IRP, the appropriate level of interaction with Ontario Hydro with respect to fuel substitution issues, the time frame for an IRP plan, and the process for plan development. Board Staff submits that by beginning a DSM process within the current jurisdictional limits, the Board will be able to determine whether or not a formal IRP process is required. As part of determining the need for a formal IRP process, the Board will need to evaluate, based on its experience with DSM, whether it will be practical, feasible, or necessary to expand the process in order to achieve the goals of IRP.

ISSUE 11

OMAA has requested that meaningful consultation with its constituency should occur. Board Staff submits that the majority of this consultation will be very difficult to pursue as OMAA has not enumerated its membership. Therefore OMAA must help the utilities identify and, communicate with, the affect parties. Further, Board Staff submits that it is important that the Board receive OMAA's input on these matters although direct consultation with individual Board members may not be appropriate. Other venues should be examined instead.

ENERGY PROBE

Energy Probe argued that rates should reflect the marginal cost of supplying gas. Board Staff agrees that in a perfect world, energy efficiency and conservation objectives would be achieved naturally through market forces. However, Staff submits that given the many inefficiencies and uncertainties in the markets for natural gas and competing energy sources, policy decisions and market intervention are required.

The thrust of Dr. Ruff's testimony is that the Board should focus exclusively on minimizing rates in evaluating resource options. Board Staff submits that to advocate the RIM test as the measure of cost-effectiveness requires the incorrect assumption of well-functioning energy markets. IRP recognizes that market barriers prevent customers from making efficient energy choices. Well-designed demand-side programs offer cost-effective choices to customers that cannot be or are not taken advantage of under market conditions. It is Board Staff's position that reliance on market forces and pricing will not be sufficient to ensure that an optimal or reasonable amount of cost-effective conservation is going to take place.

Board Staff submits that the proposal to establish non-regulated conservation divisions would greatly increase the regulatory burden and that the Board should reject Energy Probe's suggestion in this regard. Staff submits that Energy Probe contradicts itself by stating that no cross-subsidization is acceptable, and then suggesting the use of a DSM portfolio whereby financially successful programs are used to support non-sustaining programs. It is submitted that it makes no sense to allow cross-subsidization among affiliates.

Energy Probe submitted that the best way to treat externalities is to internalize them in the price of gas, but only after doing the same to other fuels. Board Staff submits that Energy Probe's position on externalities is partly based on the assumption that externalities of gas use are so small that it would be more costly for the Board to consider them than it would just to live with the effects. This explains why Energy Probe endorsed the reliance on market tests even though price signals are distorted by the exclusion of externality values. Dr. Ruff's evidence suggests that markets function best when left alone and the less intervention the better.

It is clear to Board Staff that Energy Probe's advice to the Board regarding externalities in the natural gas market boils down to: do nothing. Board Staff submits that such a course is inadvisable, as it is reasonable to believe that externality effects probably warrant some market intervention. Energy Probe's objection to an interpretation of Dr. Ruff's testimony on market imperfections to include externalities highlights the fact that the bulk of Dr. Ruff's testimony needs the qualifier: "in the absence of externalities." Considering that a major part of IRP is to consider externality values, this is a fundamental weakness of Energy Probe's position.

One of the basic tenets of Energy Probe's position is that raising gas rates will result in higher total emissions from energy sources in the aggregate, because the higher gas prices will discourage substitution to gas from more polluting competitive fuels at the margin. Energy Probe's argument that raising gas prices will increase total emissions from all fuel sources is only true if the cross price elasticity is high enough to offset the decrease in gas use. Board Staff submits that Energy Probe has not provided sufficient evidence to establish the validity of this proposition in the hearing. In the absence of supporting evidence, this proposition should not prevent the Board from considering DSM measures even if they may have small rate impacts.

FARM ENERGY ASSOCIATION ("FEA")

FEA presented evidence that the agriculture sector would like to be a player in any strategies for reducing its energy use. One example was the linkage between a small ethanol plant and a greenhouse operation to reduce natural gas use in the drying process. However, small ethanol plants, which support rural diversification, are financially viable only if they are linked to another operation, such as a greenhouse.

Dr. Stahlberg identified some financial and informational barriers to the implementation of these sorts of projects, and made a number of recommendations for utility actions to overcome such barriers. Board Staff recommends that the Board encourage the utilities to include representatives of the agricultural sector in its consultations and in the externalities working group. Board Staff further submits that the process is not sufficiently advanced at this point for the Board to determine whether regional offices to accommodate agricultural customers or specific guidelines for the utility to assess all agricultural linkages are necessary. These would be items for the utilities to consider when developing and conducting their consultations and DSM plan development.

EXECUTIVE SUMMARY OF CENTRA GAS (ONTARIO) INC.

I. INTRODUCTION

Centra Gas Ontario Inc. ("Centra") supports the pursuit of the goals of IRP in Ontario. Centra has been an active participant in all phases of the E.B.O. 169 proceeding and has found the consultative, cooperative approach adopted by the Board to be helpful in allowing the utility to develop its understanding of the issues and the positions of other parties.

Centra has based its positions on the issues which have been the subject of the E.B.O. 169 proceedings on the following important principles;

1. The implementation of IRP in the Ontario natural gas industry will be an evolutionary process.

2. IRP should be implemented in manner sufficiently flexible to accommodate the unique characteristics of each LDC.

3. IRP must recognize the LDC's obligation to balance the interests of each of its stakeholders.

4. Natural Gas must remain a cost competitive energy source, particularly in view of its environmental benefits.

IRP should focus on the implementation of cost-effective DSM programs. An appropriate set of feasibility tests will result in the consistent evaluation of demand and supply side options.

Centra believes that Ontario natural gas distribution utilities should move forward with additional demand-side efforts expeditiously. Recognizing that the introduction of DSM may introduce new uncertainties to the planning process, Centra is advocating a phased-in approach. This will permit the utility to develop the experience, information and systems required to forecast program impacts and will allow the careful testing of options through pilot programs. This in turn will manage the risk to which Centra and its customers may be exposed during the initial period of implementation.

ISSUE 1

Centra continues to support the Consensus Position Statement of October 9, 1992 on this issue.

The consensus statement notes that while the forecast load impacts of the DSM options proposed for implementation should be incorporated into the utility's demand forecast, the base case supply plan should be flexible enough to accommodate variance between forecast and actual DSM program results. Centra expects that the degree of supply flexibility required will decrease over time as the utilities develop the data bases and forecasting systems necessary to improve the accuracy of DSM program impacts. The potential to reduce the supply plan flexibility and to recognize the related savings is one reason why Centra supports a phased-in approach to IRP.

ISSUE 2

Centra continues to support the Consensus Position Statement of October 9, 1992 on this issue.

Centra would like to place particular emphasis on the portion of paragraph 2(c)(ii) of the Consensus Position Statement which notes that: "the resulting rise in rates must not entail second round net societal costs that are expected to exceed the first round net societal benefits of the demand management program (eg. if higher rates cause customers to switch away from gas, the resulting net social costs could exceed the net social benefits of the program that is being financed by the higher rates)".

Natural gas is the least environmentally damaging of the fossil fuels and is the preferred energy source for many end use applications. The evidence indicates that there is more potential environmental and social benefit in fuel switching than in gas conservation. Therefore, while DSM action should encourage efficiency it should not materially discourage fuel switching to gas or encourage fuel switching from gas. It is for this reason that the Consensus Position Statement highlights the concern about second round social costs if natural gas prices are allowed to rise excessively.

The competitive position of gas is a function of the relative unit cost of fuel and the relative capital cost of the equipment in each market in which it is sold. Given the difficulty of forecasting the effect of price changes on fuel switching, the sensitivity in many markets to small price changes, and the environmental impacts of fuel switching, the degree to which prices should be allowed to increase as a result of a DSM portfolio will be an important issue in the choice of an appropriate portfolio.

ISSUE 3

Centra continues to support the Consensus Position Statement of October 9, 1992 on this issue.

Centra suggests that the working group is more likely to succeed if it develops, by agreement, its own specific objectives, work plan and time table. Initial discussions within the working group on November 5, 1992 indicate that the work plan would probably include the following:

a) the identification of externalities that should be considered in an IRP context;

b) a survey of approaches used in other jurisdictions;

c) obtaining relevant existing studies on externalities; and

d) determining the preferred approaches to quantifying and monetizing externalities and reporting them to the Board and the parties to E.B.O. 169.

ISSUE 4

Centra continues to support the Consensus Position Statement of October 9, 1992 on this issue.

The Consensus Position Statement stipulates that a deferral account should be established for operating "and/or" capital expenditures. Centra believes that capital expenditures are likely to be the larger of the two types of DSM expenditure, and therefore should be included in the deferral account if the account is to meet its objective.

The deferral account achieves two objectives:

a) it reassures interested parties that the utilities will not be constrained from the aggressive pursuit of DSM programs by cost considerations; and

b) it balances the interests of the utility and the customers in the event that DSM programs are more successful than anticipated.

ISSUE 5

Centra continues to support the Consensus Position Statement of October 9, 1992 on this issue.

Centra maintains that cost allocation principles used to allocate DSM costs should be consistent with those used to allocate other expenditures. However, the nature of certain DSM costs may warrant the development of new cost allocation factors.

ISSUE 6 - PART I: INCENTIVES

Centra continues to support Consensus Position Statement of October 9, 1992 on incentives.

Centra believes that incentives must be significant and the potential to realize the incentives real if they are to be effective in motivating behaviour. The successful application to claim an incentive will likely require support which can only be supplied by measuring and monitoring systems not yet in place. For this reason that Centra has indicated that the utility may not apply for such incentives initially.

Centra believes that the introduction of penalties is counter-productive to a process which seeks to encourage the pursuit of innovative new programs. The additional risk imposed by the penalties may serve to dampen the enthusiasm of the utility to attempt unproven programs.

ISSUE 6 - PART 2: DECOUPLING

Centra continues to support the Consensus Position Statement of October 5, 1992 prepared jointly with Union.

Decoupling is a complex and troublesome regulatory mechanism which will require significant adjustments to the method of regulation in Ontario. There is good reason to suppose it raises many more problems than it solves and that it may be counter-productive to its objectives. There is little experience with this mechanism in other jurisdictions, and such experience as there is does not support the conclusion that decoupling is appropriate in this regulatory environment at this time.

Decoupling is intended to address a perceived disincentive for the utility to pursue conservation in the period between rate cases. Between rate hearings, the utility is seen as having a disincentive to reduce sales below forecast levels and therefore not to pursue conservation programs which would reduce sales.

Under the existing regulatory regime in Ontario, which utilizes a forward test year and allows for annual rate applications, this issue is small in relation to the scale and complexity of the solution proposed. The Ontario regime does not discourage conservation. It provides a disincentive to the utility to aggressively pursue planned conservation programs during the rate year after the case has been decided. However, there are many other factors that indicate that the disincentive is insignificant:

a) The extent to which the revenue incentive dissuades the utility from conserving beyond the levels forecast as an alternative to gas sales which do not represent cost effective energy usages is limited.

b) The perceived disincentives do not operate other than between rate hearings and do not and are not seen to discourage utilities from planning aggressive DSM programs.

c) In reality the "trade-off" between conservation and increase sales really occurs, because both can and do go on simultaneously.

The evidence indicates that the introduction of decoupling into the regulation of natural gas utilities in Ontario today can be anticipated to result in a number of significant problems, the cost and complexity of which can be expected to significantly outweigh the impact of the issue decoupling is intended to address. Decoupling can be expected to result in:

a) Advantageous sales of gas being discouraged;

b) Distorted decision making and perverse incentives;

c) Adverse rate impacts and perverse price signals;

d) Increased regulatory complexity.

Centra submits that U.S. experience with decoupling does not provide a foundation on which this Board should conclude that decoupling is necessary or desirable. With the exception of California, it has been introduced only for some electric utilities in three states, within the last two years.

Centra submits that the Board should be cautious in drawing any conclusions about the need for and impact of decoupling on the basis of U.S. experience related to electric utilities, because of the significant differences between gas and electric markets. These include the fact that electricity is not generally as vulnerable to competition as natural gas so that the concern about the rate impact of decoupling may not be so marked.

ISSUE 7

Centra continues to support the Consensus Position Statement of October 9, 1992 on this issue.

ISSUE 8

Centra continues to support the Consensus Position Statement of October 9, 1992 on this issue.

ISSUE 9

Centra continues to support the Consensus Position Statement of October 9, 1992 on this issue.

ISSUE 10

Centra continues to support the Consensus Position Statement of October 9, 1992 on the issuance of guidelines, consultations on DSM programs, and consideration of DSM programs in specific rate cases.

The issue which remains in contention with respect to Issues No. 9 and 10 is the question of the need for an extension of the Board's jurisdiction.

Centra submits that to undertake what would inevitably be a time-consuming, complicated and costly process of legislative amendment would only be justified if there were a specific and necessary objective identified. The history of this Board's exercise of its jurisdiction demonstrates clearly that the Board has considerable authority to enable the achievement of the DSM objectives which have been identified in this hearing.

EXECUTIVE SUMMARY OF CAESCO

INTRODUCTION

CAESCO believes that Energy Service Companies ("ESCOs") and gas utilities have complementary strengths and should work together to implement demand side measures among natural gas consumers in the institutional, commercial, industrial and multi-family residential sectors. CAESCO's view is shared by each of the major gas utilities in Ontario, who have all testified that they would be prepared to work with CAESCO and that they consider CAESCO to be a strategic ally in the delivery of demand side programs. (Transcript: Centra at p. 263; Consumers at p. 660; Union at p. 920) These complementary strengths are set out under Issue 12 ESCO/Utility Cooperation. The Government of Ontario also calls for ESCO/utility collaboration in its policy document, "A Framework for Energy Efficiency & Conservation in Ontario".

ISSUE 1 DSM COSTING METHODOLOGY AND INCLUSION IN THE DEMAND FORECAST

While CAESCO is a party to the Consensus position it reiterates a previously stated concern: that the value of DSM, based on avoided costs, does not become the cost of DSM thereby leading to inappropriate or unnecessary financial incentives. This has the potential to not only cause distortions in the market place that affect customers' decisions, but it also hampers the ESCOs' efforts to structure DSM contracts on the basis of market value.

If utilities design programs that allow a financial incentive to cause program costs to rise to the level of then avoided costs estimates, it would not only upset the equilibrium and financial structure of ESCO projects, but could also result in unnecessary costs to non-participating ratepayers.

With respect to the use of demand side measures to meet utilities forecast demand, CAESCO has testified that in the sectors with which it was familiar, fuel savings (gas or oil) normally accounted for about 45% of total dollar savings generated by the retrofit project, (with the balance electricity). There is, therefore, the potential for gas savings in the sectors where ESCOs are active.

ISSUE 2 APPROPRIATE COST-EFFECTIVENESS TESTS

CAESCO's position on this issue is that of the majority; that is, DSM should pass the societal and ratepayer impact tests. However, the current variation in monetization factors for externalities should be thoroughly researched and evaluated through the working group, as decided during the hearings. Again, CAESCO's concerns involve incentive levels that may be unnecessarily high, which can happen when programs are undertaken that do not pass a ratepayer's test but pass a societal test, which may be driven by arbitrarily derived monetization factors. In most U.S. jurisdictions where IRP has been implemented, it is the Total Resource Cost Resource Cost Test that is the ultimate determinant. The Societal Test is used in the initial screening process only.

It is noteworthy that ESCO programs achieve their load-saving goals and successfully reduce environmental externalities without the need for utilities to internalize any externality costs. This added benefit should be factored into the utility's DSM plans.

ISSUE 3 INCLUDING EXTERNALITIES IN THE COST ANALYSIS OF DSM Programs

Societal and environmental externalities to the extent that they can be identified, quantified, and monetized with a satisfactory level of confidence, should be a factor in determining the cost effectiveness of programs vis-a-vis the Societal Test.

ISSUE 4 RATEMAKING TREATMENT FOR DSM INVESTMENTS

CAESCO is a party to the consensus statement on the cost recovery issues. In keeping with generally accepted accounting principles, any DSM operating expenses, or one-time costs that occur in a current period should be expensed while longer term DSM investments should be capitalized and included in the utility's rate base.

CAESCO is also in agreement with the concept of a deferral account and would even take it one step further for the sectors in which they operate. Joint utility/ESCO programs could be included in these accounts with the rebate funding occurring at periodic intervals after the load savings are realized and documented. In this manner any potential DSM financial risk is removed from the utility, while it potentially earns a return on the program funds. At the same time the risk associated with the lack of information on persistence is mitigated.

ISSUE 5 WHO SHOULD PAY FOR DSM PROGRAMS

The U.S. experience indicates that cross-subsidization can become an issue and the principle of *user pay* should be followed. This has always been the basis for ESCO/client contracts, where clients accept their current level of utility bills until the DSM investment has been fully recovered by the ESCO or the contract expires. CAESCO prefers to see the gas utilities' programs for commercial, institutional, and industrial customers structured similarly. The CAESCO membership is offering to work with the utilities to design programs with benefits that not only outweigh costs but also provide a means of serving the energy efficiency needs of these sectors, without a financial investment until the savings are realized. This provides the utilities the opportunity to implement programs in all sectors; prescriptive programs in the residential and small commercial markets, and customized comprehensive programs for the larger commercial institutional and industrial facilities.

ISSUE 6A SHAREHOLDER INCENTIVES

It is CAESCO's position as a party to the consensus, that utilities should determine the benefits and feasibility of financial incentives to implement DSM as a business policy decision; they should be made whole and not be penalized. However any financial incentives that are developed should maintain a level playing field between the utility's implementing a program directly or working through ESCOs.

ISSUE 6B DECOUPLING

CAESCO offers a few general observations on the decoupling issue to the involved parties. Decoupling mechanisms are relatively new and unproven among electric utilities (California is the exception). The rationale for decoupling in the electricity industry involved the extensive risk exposure to the utility when planned revenues did not materialize since the largest portion of the revenue requirements were fixed rather than variable costs. This is not the case however for gas utilities. There have been a few gas utilities who have proposed decoupling vis-a-vis weather-normalization clauses; and regulators have been reluctant to accept these clauses in these cases for several reasons. Traditional ratemaking and the rate of return allowed to stockholders has included the risks posed by weather and the level of economic activity. A decoupler removes that risk and places the burden directly on ratepayers.

ISSUE 7 DSM POTENTIAL & MONITORING & EVALUATION

CAESCO is a party to the consensus position on this issue and would only wish to express its willingness to lend expertise in identifying the technical and achievable potential among the commercial, institutional, and industrial sectors. Estimating the potential for load savings through energy efficiency among these sectors is, and should be, an entirely different approach than determining the potential for prescriptive measures among residential and small commercial customer sectors. ESCOs can provide their knowledge and expertise, to ensure that the introduction of new measures are well-planned and coordinated so that they do not create a malfunction of other systems.

ISSUE 8 RATE DESIGN, ISSUE 9 JURISDICTION AND ISSUE 10 IMPLEMENTATION OF IRP

CAESCO is a party to the consensus position on these issues.

ISSUE 11 GUIDELINE REQUIREMENTS

> "If the Board were to decide to call for the development and submission of DSM plans by utilities, what issues must be addressed by the Board in its EBO 169 report and what specific guidelines must be provided." (Tr. 3094)

CAESCO would like to see the Board address the issue of utility/energy service company co-operation. The Board should note that the utilities have each declared the ESCOs to be strategic allies or potential partners in the delivery of demand side measures and should encourage the utilities to meet with CAESCO to discuss collaboration between the two industries before developing specific demand side programs, and to develop programs that recognize the role of energy service companies in the sectors where they are active. The discussion should cover the issues referred to in this Executive Summary in particular section 12.

The Board should also provide Guidelines:

- for recovering program costs over a period of years to reduce or eliminate the chance of not recovering costs due to any jurisdictional constraints.

- for the methodology to calculate avoided costs which should be determined based on a consensus among the utilities, possibly with the Board Staff as facilitators. Allowances should be made for the absence of conditional demand forecasts which are required to calculate avoided costs with any level of confidence.

- to guarantee cost recovery of DSM investments once a program has been accepted by the Board. They should include;
  - capitalization rates
  - short term carrying costs (eg. AFUDC: Allowance for Fuels Used During Construction)
  - definition of the administrative and overhead costs that may be capitalized or expensed
  - explicit definition of the parameters and description of funds associated with a deferral account especially since it is being proposed that prudence reviews occur after the funds have been spent

- for cost allocation for program costs not recovered from participants.

- to define lost revenues.

- of its expectations on the use of customer contributions and for incentives for the utilities to implement DSM.

- for the required periods for monitoring and evaluating programs, load impacts and the process itself.

- for the protocols for modifying or eliminating a program.

- to provide an allocation process for budgeted DSM dollars to implement programs across all sectors.

ISSUE 12 ESCO/UTILITY COOPERATION

CAESCO is of the view that the gas utilities and the Energy Service Companies have many complimentary strengths in the marketplace for demand side measures. Energy Service Companies ("ESCOs") are private businesses which are expert in the art and science of creating sustainable energy savings in facilities. The following aspects of their business are particularly relevant to the utilities' objectives and planned activities to achieve effective demand side measures.

First, ESCOs guarantee that the energy savings generated by the retrofit projects which they implement will be sufficient to repay their investment in the project, including profits, over the term of the contract. The ESCO is paid by its client only to the extent the projected savings are actually realized. In that sense the ESCOs business is performance-based. Either the ESCO consistently realizes its savings targets or it cannot remain in business. It is therefore accountable for the savings in a direct, commercial sense. It follows that any funds the utility were to spend in assisting ESCOs to penetrate markets more quickly, would have a high probability of resulting in real savings. If, for example, the gas utilities were to implement a program akin to the Guaranteed Energy Performance Program ("GEPP") of Ontario Hydro, they would only be paying for savings actually realized. The utilities would not be spending money based only on the expectation that savings might or should be forthcoming. The certainty of achieving the savings reduces the utility risk in engaging in demand side measures.

Second, the ESCOs take a comprehensive approach to the retrofit of a facility. All potential energy savings measures are considered and a package of incentives with a commercially viable payback is agreed to between the ESCO and the customer. As a result of the comprehensive approach the proposed retrofit measures are technically coherent and mutually reinforcing. For example, lighting and HVAC measures are considered together so that, lighting retrofits which would, if done in isolation, increase the need for further cooling, are avoided. Cream skimming or the practice of selecting just the shortest payback measures, which make the longer payback retrofit measures unfinanceable, is also avoided. Measures with varying payback periods are blended together into a project with a commercially acceptable payback period. Generally speaking, it is in the ESCO's interest to enlarge the project as much as possible up to a maximum commercial payback. Finally, both gas and electricity savings measures are considered together in ESCO projects which leads to reduced auditing, marketing and monitoring expenses. The last point is particularly important as Ontario Hydro has substantial demand side programs available, and in order to minimize costs and maximize the effectiveness of demand side measures both electricity and gas savings measures should be considered and implemented in tandem. The ESCO can work with both the gas utility and the electric utility and integrate their efforts in respect of a particular facility.

Third, ESCOs create sustainable savings. If the savings do not persist over the contract term (5-9 years) the ESCO does not recover its investment and, if savings are consistently below projections, it may go out of business. To the extent utilities spend funds to support ESCO efforts, they can be assured the savings that result will be sustained over time.

Fourth, ESCOs pay for the retrofit measures and recover their investment including profits, from the stream of savings generated. Ultimately, the user pays in the sense that it must repay the ESCO from savings and this fact introduces a commercial perspective and discipline into the transaction. There is no giveaway with an ESCO project. The project size and payback is based on its value to the energy user. The energy user pays for all of the project costs from savings and must make a conscious decision about the period of time it is prepared to cede the dollar value of the energy savings to the ESCO. The ESCO essentially removes the transactional burden.

Fifth, the presence of ESCOs in the marketplace allows the utilities to leverage their own scarce resources. To the extent that ESCOs are financing retrofit measures, the utilities do not have to. Savings are being created with little or no monetary contribution from the utility. Consequently were the utility to invest a modest amount of funds in, for example, workshops or seminars with clients to assist ESCOs in their marketing efforts, and thereby enabled them to penetrate selected markets more quickly, the leverage the utility would obtain would likely be very large. Further, were the utility to invest in ESCO projects via a GEPP-like program, the leverage on the utility investment would still be substantial since the ESCO, and ultimately the end user, would be paying the largest part of the cost. The level of the utility incentive could be set so that total program costs are well below its avoided cost and yet allow the ESCO and the end user to increase the size of the retrofit. Further, it may be feasible for the utility to coinvest in projects with ESCOs under circumstances where the ESCO guaranteed the utility an appropriate return on its investment. These possibilities should be discussed at meetings between CAESCO and each utility. However CAESCO advises caution in the use of user financial incentives in that they may distort the market place. As a short term measure, they can be justified to "jump-start" the demand side industry.

Sixth, the ESCOs have the capability to implement projects immediately. They have both the analytical and implementation skills and represent a viable delivery vehicle for utility programs. They have penetrated various end use markets, are knowledgeable about customer needs and buying behaviour in those markets and have much information that would be useful to utilities in assessing energy savings potential and designing market strategies and programs. To the extent the utility works with and through ESCOs, it need not indulge in a time-consuming process to set up a parallel delivery mechanism and embark on a costly search for information.

Seventh, the ESCO is such an effective delivery mechanism for demand side measures because it offers a turnkey service to clients ranging from energy audit and analysis through detailed design to construction and financing. The ESCO addresses the overall transactional burden. It provides not only money, but the managerial and technical wherewithal for the client to complete the project. Clients often don't have the required technical knowledge, lack the managerial time to focus on the energy savings issue and lack the capital. The services offered by the ESCO address all of these needs. In addition ESCOs reduce client confusion by offering in-depth knowledge of all utility and government incentive programs, equipment options, and the like. Customers can be confused into inaction by too many competing messages from various purveyors of programs and services. ESCOs' delivery avoids this.

Eighth, utilities would also reduce their program marketing costs by working through ESCOs since the ESCOs have already identified targets and do this in the normal course of business. In effect, they can bring clients to the utility. Conversely, for a modest investment, utilities can assist the marketing efforts of ESCOs by acting as a bridge between the ESCOs and their clients. Union Gas recognized that it might assist ESCOs marketing their services to its clients. (Tr. 920)

Ninth, ESCOs must also closely monitor savings and do the necessary "fine-tuning" to ensure savings are sustained. Since these costs are spread over a large number of projects, ESCOs can perform the monitoring and measurement functions relatively 6 efficiently. They must also measure savings in order to determine the client's bill on a regular basis. Accordingly, to the degree a utility works with or through ESCOs it can hold program monitoring and measurement costs to a minimum.

The ESCO industry is regulated and endorsed by both the federal and the provincial governments. Ontario Hydro has qualified ESCOs for the GEPP program through a screening process, as have the federal government for its FBI initiative. The federal government is promoting energy performance contracting with ESCOs as a way to reduce energy costs in federal facilities at no cost to the government. CAESCO is in the process of launching a certification program for its membership which will require that the ESCOs not only maintain certain core capabilities but continue to remain abreast of recent technological developments.

The features of the ESCOs business described above, in particular the fact that the ESCO takes the risk of energy savings being generated, can reduce the program risk to the utilities. Sustainability of savings means the utility can rely on the ESCO generated savings in its resource planning.

The utilities also offer the ESCOs a number of advantages, including enhanced credibility in the market place. As Dr. Levy stated at p. 2962,

> "I think when we look at the strengths that the utilities bring to our marketplace, one of the strengths we feel the utilities have is the ability to, in the customer's mind, bring credibility to the activities that our members propose, in other words, in the sales cycle and in the marketing, having a utility support the efforts of what our companies are doing accelerates the decision making at the customer level."

Energy performance contracting is still a relatively new approach to achieving energy savings and the industry is only a few years old. Various end users sometimes think that the ESCO story is "too good to be true", and need to be persuaded that the concept works in practice. Utilities can also assist the ESCOs by helping the ESCOs market their services to utility clients, via information programs, workshops, seminars, and other methods of bringing their clients and ESCOs together.

With respect to financing demand side measures, ESCOs would appreciate utility assistance in working with financial institutions to design appropriate financial instruments to securitize the predictable cash flow from energy savings measures and, more generally, to help the financial community better understand the significant business opportunity the performance contracting industry represents.

ISSUE 13 REPLY ARGUMENT

CAESCO's Reply Argument focused on three issues raised by Board Staff in its Argument-in-Chief, competition between utility DSM programs and established suppliers of energy efficiency products and services, shared-savings incentives for utilities to implement DSM, and the benefits ESCOs can offer utilities.

First, Board Staff in its Argument concerning cost effectiveness has touched upon an issue that CAESCO agrees with completely and finds worthy of comment. On page 16, Board Staff states,

> "If the utilities are to offer DSM programs that will compete with other major commercial distributors, it will have to be done at a price that is less than that currently available in the market place, or the utility will have to differentiate its product or service. If not, the utility will have very few customers buying their products. In addition to the problem of undercutting the existing market, if the utilities are to sell their DSM programs at a lower price than commercial suppliers, many financially non-sustaining programs will result."

ESCOs are commercial suppliers of energy efficiency services to customers. Their projects are structured and costed so that the load savings that are generated within the contract period are sufficient to just cover the cost of the investment and a profit. CAESCO prefers to work with the utilities to design and implement their DSM programs so that they reduce the payback period for all stakeholders rather than find itself in a competitive relationship with utilities that results in programs that are either financially non-sustaining or result in duplicative efforts.

Second, the Board Staff's argument on financial incentives seems focused on shared savings, as were the oral discussions during the hearings. CAESCO firmly believes in the shared savings concept as a means of incentivizing the utilities. However, it may not be the most effective approach for some DSM measures.

Current ESCO programs are initiated through the ESCOs' financial investments. They rely on a sharing of the energy dollars generated by the load savings with the customer who shares in lower energy bills after the ESCO payback period. While this is not the forum to work through the particularities of a joint utility/ESCO program serving a <u>trio</u> of stakeholders, it should be noted that a shared savings approach may not meet the needs of all these stakeholders simultaneously, at least in the early years of the program. CAESCO is concerned that any financial incentives that are provided to the utilities for DSM investments create and maintain a level playing field between those programs a utility might implement directly with end users and programs a utility might implement with or through ESCOs. The incentives should be sufficiently broad in scope as to allow them to be tailored to different types of DSM programs.

Third, at page 66, Board Staff recognizes the value of ESCOs to the utilities but states that ESCO programs are substantially different from the programs that are most logical for the utilities to adopt. CAESCO urges the Board to encourage utilities not to think of ESCO programs as efforts apart from their own. It is CAESCO's position that <u>all</u> customer classes should be included in the utilities' portfolios of DSM resources not just in a nominal sense but in a material sense. ESCO-linked programs, which focus on institutional, industrial, and commercial customers, should be adopted by the utilities along with the prescriptive programs that have been successful in the residential and small commercial markets. CAESCO advocates ESCOs and utilities working together in the design and implementation of DSM rather than moving forward on parallel paths. There are opportunities to realize savings in every sector and DSM programs need support from all customer sectors if they are going to become a viable resource.

EXECUTIVE SUMMARY OF COALITION OF ENVIRONMENTAL GROUPS

1. INTRODUCTION -- THE ENVIRONMENTAL IMPERATIVE

Judicious regulation of the gas sector offers significant opportunity to reduce Ontario's contribution to the problem of global warming. Natural gas burning in Ontario is responsible for 25% of the CO_2 emissions in the Province. With fuel switching to gas from dirtier fuels, it may make up a higher proportion of the total in the future. Clearly, in order achieve significant reductions in CO_2 emissions, both fuel switching and highly efficient use of gas will be required.

Ontario Government policy

In June 1992 the Government published A Framework for Energy Efficiency and Conservation in Ontario. It contains a number of clear messages for the Board in developing an IRP framework.

- "Energy efficiency and conservation are the first priority for meeting Ontario's requirements for energy services.
- Where barriers to an efficiently functioning market exist, other tools, such as policy direction, incentives **or** regulation or supplier development initiatives will be used.
- Ontario Hydro and **the natural gas utilities,** in partnership with others such as the municipalities, municipal utilities and other energy suppliers, **will be key players in the planning and delivery of energy efficiency programs and policies.**"

Making particular reference to the gas companies, the policy outlines the following directions:

"...greater efficiency measures are needed in the gas sector.

- Natural gas utilities, in conjunction with other energy supply and service companies, are expected to be central players in achieving the Province's energy efficiency objectives.
- Ontario's natural gas distributors should assume a leadership role by encouraging the purchase and rental of energy efficient equipment, **providing customer incentives** for the purchase of energy efficient products and materials, and advising customers on the use and installation of products designed to improve energy efficiency and conservation." (emphasis added throughout)

How should the Board honour this direction? For Ontario to be a leading jurisdiction, as suggested by government policy, three mechanisms are required: DSM program cost recovery; decoupling to deal with lost revenue effects; and positive financial incentives.

Business as usual is not an option.

No one has suggested that the market on its own will internalize the environmental costs of energy use. Traditional government environmental regulation has sought to control emissions from key sources. This method has its place, but given the variety of sources and situations, control orders and standards will be both inefficient and insufficient.

Two approaches have been suggested in this hearing to augment existing controls -- internalization via taxes, and internalization via IRP.

Some advocate changes to the pricing and taxation regime to include environmental costs in all fuel prices. While this approach has obvious attraction, the government has indicated that "these actions can have serious repercussions for Ontario's economy and could severely affect the competitiveness of Ontario industry." In an economist's perfect world, all jurisdictions would impose such universal taxes, and the government's reservation would disappear. We do not live in such a world.

The second approach is that encompassed by IRP. It can be characterized as a gradual internalization, where the full social costs are considered at the point of making investment decisions. IRP is really about ensuring that funds will be invested up front in efficiency, in order to gain long term benefits of reduced operating and environmental costs. In that respect, there sometimes will be rate impacts, offset in whole or part by reductions in bills. Rate impacts will occur where the savings accrue in the form of a cleaner environment. Further, those who choose not to participate, will quite appropriately, be asked to share in the cost burden of internalizing previously externalized environmental damage.

The CEG notes that the consensus statements developed by many of the parties to this hearing reflect widespread agreement as to what must be done, and provide significant guidance to the utilities in developing DSM plans. The Coalition strongly urges the Board to adopt these positions. Hereafter, we identify the CEG's preferred resolution in areas where there remains disagreement among the parties, and make suggestions on how the guidelines could be further elaborated upon.

ISSUE 1

A: Costing methodology -- Refer to consensus statement.

B: Extent of reliance on DSM

Within the consensus positions, parties to the hearing have agreed that a societal cost test and inclusion of externalities are among the key tools for carrying out this task. The CEG takes from this that a paraphrased and clarified definition of IRP in this hearing would be "...to meet society's energy service needs at the lowest total social cost".

Given this background, the definition requires that all DSM which is less expensive than supply should be pursued, where "less expensive" includes both the financial and the external costs of both options. Only a strategy that pursues all such DSM will succeed in achieving the result of minimizing the total cost of meeting society's energy service needs.

Practically, this means that all DSM measures and programs that pass the Societal Cost Test as defined and applied under Issue 2 should be pursued vigourously. This test indicates whether or not the DSM option (and its second order effects) is cheaper than avoided costs, including externalities. Some exceptions, properly documented and justified can be made, but these exceptions should not become the rule.

An approach that achieves only a portion of the cost-effective DSM potential will, by definition, result in higher cost (energy bills and environmental costs) than necessary.

Reject arbitrary DSM limits

The Board should reject a priori limitations on this proposal, such as "no rate increase from the portfolio". Such a policy could serve to unduly restrict DSM activity and arbitrarily limit the benefits of IRP.

A "zero rate impact portfolio" is inappropriate, because this approach would likely result in missing DSM opportunities which will become "lost opportunities". Without a willingness or ability to invest up to the full social value of the measures, utilities' DSM programs will not go as far as is socially cost-effective. The effect of separating DSM measures into "cheap ones now, more expensive ones later" is to increase the overhead cost such that the cost of obtaining the second round of measures is no longer cost-effective -- it is a recipe for "cream skimming" that must be rejected.

ISSUE 2 -- See consensus statements.

ISSUE 3 -- Should societal and/or environmental externalities be included in the cost analysis of demand side management programs? If so, how should these costs and benefits be included?

Externality valuation is consistent with user pay

It has been implied that externality valuation involves raising customer's rates to confer benefits upon others. In fact, the purpose is to have the customers who are currently enjoying the energy service benefits gradually take responsibility for the costs of reducing the externalities they impose on others:

> MR. CHERNICK: A. The primary purpose of monetizing externalities...is to internalize the costs which are currently being imposed by the users of the energy on the rest of society, internalize that in the decisions about the energy source without necessarily imposing the full costs on those users. It's consistent with the principle of polluter pay, but without some of the burdens of the direct taxation. [V.10, pg 1453]

Partial monetization is better than none - precision is not necessary

Where environmental impacts are certain to be created, but the amount is uncertain, then zero is clearly the wrong answer to valuing those impacts.

> "Externality estimates need not be perfect or completely accurate to be useful in energy planning. Energy planners routinely use estimates and approximations where necessary. There is probably no one in this room who can precisely estimate the cost of gas in the year 2000, if they are I think they will probably be very wealthy.
>
> Energy planners routinely use estimates and approximations when they have to. The appropriate standard to be applied is whether the values incorporated are so imprecise and inaccurate that we will make poor decisions when externalities are considered than if they were ignored.
>
> As has often been stated in the current system, the value of social and environmental externalities has generally been set at zero, which would appear to clearly understate the value of these existing externalities.
>
> Furthermore, the recently stringent environmental regulations and restrictions on energy supply and consumption that have been applied over the last several decades, reflect the fact that society believes that the existing residual damages are significant and should be reduced.
>
> To the extent that this trend of more stringent regulation is likely to continue, the application of externality values can be viewed as a forward looking exercise that will help to reduce the cost of complying with those future regulations." [Mr. Goodman V.14, pg. 2412]

The Board's original discussion paper (Exh. 1.11, pg 131) observed "Planning in general is fraught with uncertainties, so their presence should not necessarily prevent considering externalities."

No need to assess environmental problems

Adopting an approach of including externality costs in the gas system planning process does not require the OEB to become expert on all the environmental issues and their severity in order to value them appropriately. Adoption of the Cost-of-Control approach leaves these decisions to the environmental regulators, and simply values reductions in these pollutants from DSM activity at the value of avoiding the cost of controlling them by the alternative method.[1]

Can externality policy work without other fuels being covered?

Pending application of this approach to other fuels the Board should not delay its application to gas. The OEB should take a leadership role. Just as the absence of child labour laws in competing economies was no excuse for delaying reform at home, the absence of adequate environmental impact internalization in other fuel sectors should be no excuse here. Monetization of externalities in the gas sector will surely speed the application of that approach to other fuels, whether in OEB jurisdiction, or elsewhere.

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[1] Using the cost of control approach has been supported by Union Gas (Ex.4.1, pg 4-46), Centra Gas (Ex.1.9, V.3, pg 687), the CEG (V.10, pg 1458), the Consumers Association (Ex.6.2, pg 2) and Pollution Probe (V.18, pg 3401). At V.5 pg 591 and V.6 pg 823, Mr Taylor from Consumers Gas endorsed this approach as well.

ISSUE 4 -- See consensus statements.

ISSUE 5 -- Who should pay for DSM programs? Should the principle of user pay apply to DSM programs?

It is the CEG's position that the existence of market barriers and imperfections, including the externalization of environmental costs, necessitates various actions, including the incenting of conservation measures by public utilities. Some object to this approach as being in conflict with user pay. However, the CEG submits that this approach is in accord with the polluter pay principle and is therefor entirely consistent with user pay broadly defined. Mr. Chernick discussed the point in the context of externalities:

> Given the role of externality valuation it's particularly appropriate to apply externalities in the valuation of demand management where all customers are paying for measures and those customers who choose not to participate in the programs and remain non-participants, have the largest environmental effect, impose the greatest costs on other parties and, therefore, should be paying the largest part of the costs of the programs intended to mitigate or offset some of the effects of their actions. V.10, pgs 1453/54

ISSUE 6 -- Decoupling and Incentives

Rationale for Decoupling and Shareholder Incentives

The rationale for incentives and decoupling is the need to obtain all appropriate DSM, not just the most lucrative, easiest, most obvious, or least threatening to the utility or its affiliates.

Even if the regulatory regime were neutral as between conservation and supply (as we argue it must become) there are at least four reasons for creating a positive tilt in favour of conservation through use of "carrots and sticks".

First, the reality of institutional inertia must be overcome.

Second, all three LDCs are controlled by shareholders with major upstream gas interests. Even in the absence of affiliate gas transactions, there is a conflict of interest with respect to conservation aspects of DSM. Conservation will affect the market for, and price of gas. Especially in the early days of gas IRP, upstream interests will have an interest in supporting a less aggressive approach among the precedent setting utilities. Accordingly, this conflicting interest must be overcome by regulatory incentives favouring conservation.

Third, in the absence of full cost internalization and marginal cost pricing, customers do not see a correct price signal that reflects true costs. For this and related reasons utility action is required to overcome market barriers and imperfections at the customer level.

Finally, in recognition of the societal and environmental benefits of conservation, government policy strongly favours conservation. This Board should enthusiastically pursue that policy direction both in deference to the democratic institution and because the policy has obvious wisdom. The specifics of government policy are discussed above in the Introduction section of this argument.

The existing regulatory regime creates an incentive for the utilities to build load, regardless of its social utility. While in the long run there is an incentive to add rate base either by conservation or supply additions, in the rate year conservation efforts are positively discouraged while supply additions are positively rewarded. The existence of this "tilted field" is not in dispute. However, the utilities argue that decoupling of revenues from throughput is a response that is greater than needed to overcome the current disincentive to conservation -- that it has undesirable side-effects in terms of the impact on load building efforts and rate stability.

As we discuss at length in the body of our argument, all of the utility objections are either inapplicable, exaggerated, or the potential for negative impact is easily mitigated. Indeed, at least one concern, that weather and economic cycle variances are far greater than any anticipated conservation variance, suggests a further benefit of decoupling, that the avoidance of these risks can improve utility management and lower customer costs.

Particularly important, in our submission, is the fact that those who object to decoupling have offered no workable, fair and efficient alternative to overcome the problem.

Conclusions on Decoupling

Despite a very creative effort on the part of the utilities opposed to decoupling, the evidence in this proceeding rebuts each and every concern raised against decoupling and offers several undisputed benefits, not the least of which is a level field for conservation.

The existing regulatory regime tilts against conservation. Decoupling will level the field. It will reduce regulatory complexity. It will reduce utility business risk and therefore save customers money. It will eliminate the perverse impacts of weather and economic cycles on utility management. It will not have any significant unmanageable negative side-effects. If conservation is to be of equal profitability to utilities (let alone the most profitable course) full decoupling for all 3 utilities is a must.

ISSUE 7 -- See consensus and comments on Issue 11.

ISSUE 8 -- See consensus.

ISSUE 9 -- If the Board decides that DSM implementation is appropriate, are there any current jurisdictional constraints which need to be addressed in order to fully implement a DSM effort?

The Board has jurisdiction to implement a DSM effort including decoupling. Clarification of its jurisdiction to offer utility incentives and adjust rate of return to foster DSM would be desirable to avoid any possible challenges from reluctant utilities or other parties. Further, jurisdiction should be sought to provide advance funding to interested parties for collaborative efforts (though the utilities may fund these efforts voluntarily if given reasonable assurances of cost recovery). The ability to convene joint electricity and gas hearings should be made explicit, especially if it is anticipated that the Board may obtain regulatory powers in regard to Ontario Hydro as we suggest it should.

ISSUE 10 -- Should the Board proceed with the implementation of IRP and, if so, how should it proceed?

The Need for full IRP:

A logical approach to DSM requires evaluation of avoided costs, the cornerstone of IRP. Utilities will be called upon to defend their assumptions about avoided costs to demonstrate that they are pursuing an appropriate level of DSM. Accordingly, the work associated with IRP cannot be avoided by restricting the intended regulatory review to a focus on DSM aspects in rate cases. Supply side aspects will emerge as issues in any event. This proceeding has not adequately considered the supply side and avoided costs side of IRP. By formalizing the full IRP process the Board can ensure timely public involvement and encourage pre-submission collaboration to narrow issues in dispute. IRP will result in a reduction of regulatory risks and will ensure that social and customer costs are minimized.

ISSUE 11 -- If the Board were to decide to call for development and submission of DSM plans by the utilities, what issues must be addressed by the Board in its E.B.O. 169 Report, and what specific guidelines must be provided?

We refer the Board to Exhibit 5.1.1 at pages 3-7 - 3-11 where we provide a listing of information requirements that should be met in utility filings. In addition utilities should demonstrate how they intend to capture all lost opportunity resources.

Utilities should not simply provide a single preferred plan. Alternatives should be presented in detail.

In particular utilities should include:

- program alternatives;
- measure bundle alternatives for each program;
- alternative program costs;
- alternative measure costs;
- customer incentives by measure;
- assumed penetration of each program and measure in each customer niche;
- for each measure provide an evaluation of the impact of increased or decreased incentives on penetration;
- UCT, RIM, PCT, TCCT, SCT results for each measure and program and for the portfolio and for each alternative at each level.

Please note that we have made a number of specific suggestions throughout the argument on issues 1-10 which we do not repeat here.

EXECUTIVE SUMMARY OF THE CONSUMERS' ASSOCIATION OF CANADA (ONTARIO)

I. INTRODUCTION

1. Consumers' Association of Canada (Ontario) (CACO) is the Ontario Branch of a national organization, the Consumers' Association of Canada, formed to protect and promote the interests of residential consumers. The objective of CACO in its participation in EBO 169 has been to protect and promote the interests of residential consumers in integrated resource planning (IRP) for the supply of natural gas by the Consumers' Gas Company, Union Gas Limited and Centra Gas Ontario Inc (hereinafter referred to collectively as the LDCs)

2. CACO believes that the OEB's inquiry in EBO 169 has three principal goals, as follows:

   - To determine whether IRP should be adopted for the natural gas industry in Ontario;
   - To determine what IRP consists of;
   - To determine how IRP should be implemented.

3. CACO believes that IRP is in the best interests of residential consumers and other stakeholders, and would contribute substantially to the achievement of the Ontario government's stated policy of achieving optimum energy efficiency.

4. CACO accepts that one of the goals of EBO 169, namely the exploration of what IRP consists of, necessitates an examination of demand side management (DSM) measures. CACO believes, however, that the OEB must distinguish between the specifics of DSM measures and the broader context of IRP. CACO does not believe that a selection of DSM measures alone constitutes IRP. CACO believes taht the OEB should, in its report, provide a comprehensive definition of IRP and relate DSM measures to that definition.

5. CACO believes that the United States experience with IRP demonstrates the central importance of an effective institutional framework for IRP in order to ensure the existence of the following matters, which are themselves critical to achieving the goals of IRP:

   1. The development of effective and cost effective DSM programs that minimize the cost requirements to the utilties, both in the short and long run, as well as produce other societal benefits;

   2. An orderly and systematic way to determine what actions or resource options are most cost effective for the utility to pursue;

   3. A means to ensure public input into the process at meaningful and critical points;

   4. A body with the ability to determine and promote the public interest in IRP;

   5. A means for formal consideration of the LDCs' entire integrated resource plan.

6. CACO believes that substantial progress has been made, through the EBO 169 process, in determining whether IRP should be adopted for the natural gas industry in Ontario, in determining what IRP consists of and in determining how IRP should be implemented. That progress is embodied in the consensus positions on the individual issues identified by the OEB. However, those consensus positions are static, and do not in and of themselves suggest a method of implementation which would give maximum effect to them. The key for the OEB is to find a method of implementation which gives maximum effect to the consensus positions.

II THE ISSUES

7. CACO accepts the consensus position on Issue 1.

8. CACO accepts the consensus position on Issue 2.

9. CACO accepts the consensus position on Issue 3. The consensus position contemplates the creation of a working group to report on the recommended methodology for the treatment of externalities to be included in LDCs' societal cost tests. CACO believes that the OEB should issue separate guidelines to the working group directing it as follows:

   1. To provide the best current control costs for emissions, other than carbon dioxide, arising from the use of natural gas;

   2. To provide for carbon dioxide emissions, for which no control technology exists, a survey of the monetary values which have been proposed for the environmental effects of carbon dioxide emissions and the levels of carbon tax which have been proposed to attain certain policy goals;

3. To provide an analysis of the reasons for the wide range which exists in those numbers.

10. CACO accepts the consensus position on Issue 4.

11. CACO accepts the consensus position on Issue 5.

12. CACO accepts the consensus position on Issue 6, part 2(a) dealing with the decoupling of profits and throughput volumes. CACO is concerned, however, that a focus on decoupling may distract the OEB from the larger issues in its inquiry in EBO 169. CACO suggests that decoupling is a useful tool which can be employed in certain circumstances to promote the attainment of the goals of IRP. CACO suggests that it is essential that the OEB, in establishing an institutional framework for the achievement of the goals of IRP, provide a flexible mechanism for the optimum use of decoupling.

13. CACO accepts the consensus position on Issue 7.

14. CACO accepts the consensus position on Issue 8.

15. CACO believes that the treatment of Issues 9 and 10 is critical to EBO 169 and to the recommendations which are to be included in the OEB's report. CACO's position on issues number 9 and 10 is broken down as follows:

a) <u>The OEB's Present Jurisdiction</u>

16. CACO, together with all of the other parties to EBO 169, accepts the position that the EBO, under its present legislation, does not have the jurisdiction to do any of the following:

    1. Order the LDCs to develop integrated resource plans using criteria established by the OEB and then approve the plan and the implementation of the plan;

    2. Order the LDCs to develop integrated resource plans using a collaborative process whereby input into the development of the plan is acquired by various interested parties through working groups;

    3. Order the LDCs to develop and pursue DSM or conservation or load management programs.

17. CACO, together with all of the other parties to EBO 169, agree that the OEB has the jurisdiction to do the following:

    1. Take IRP principles into account in establishing rate base, setting the rate of return and fixing just and reasonable rates. The OEB cannot, however, fetter its discretion and must consider each case on the evidence before it and on its merits;

2. Issue recommendations on IRP and the appropriate principles and inform the utilities that these principles will be taken into account in the utility rate cases. Again, the OEB cannot fetter its discretion.

18. CACO also believes that the OEB does not have the jurisdiction to approve the cost consequences of some DSM measures, for example those which involve the payment of incentives and reflect a value-of-service approach rather than a cost of service approach.

19. CACO believes that the OEB does not have the jurisdiction to require the LDCs to consult with interested parties in the development of DSM measures and does not have the jurisdiction to impose a sanction on the LDCs should they fail to consult either at all or in a meaningful way.

20. In light of the accepted limitations on the OEB's jurisdiction, two alternative approaches are possible. One is to pursue IRP goals through DSM measures within the existing legislation. The other is to have a legislated IRP.

b) The Pursuit of IRP Goals Within the Existing Jurisdiction

21. Several parties to EBO 169 have recommended a model for the pursuit of DSM measures within the existing OEB jurisdiction. Under that model, the OEB would issue guidelines embodying the consensus positions reached in EBO 169 and would require the LDCs to present a portfolio of DSM measures based on those guidelines in their rate approval applications. In addition, under the proposed model, the LDCs would voluntarily consult with stakeholders on DSM programs. The nature and extent of that consultation would be left substantially in the discretion of the LDCs. The guidelines would give a substantial measure of assurance to the LDCs that investments in DSM measures would be accepted, now and in the future, for rate-making purposes.

22. CACO submits that the model outlined in the preceding paragraph would be inadequate to achieve the goals of IRP, for several reasons. Chief among those reasons are the following:

    1. Under the existing OEB jurisdiction, guidelines are not binding. Any attempt to enforce those guidelines brings with it the risk of a court challenge to the correctness of the OEB's actions;

    2. All DSM measures must be evaluated solely on the criteria of their relationship to rates. The OEB may not be able to accept all DSM measures within the existing legislation, for example, those predicated on incentives or a value-of-service approach;

    3. The OEB, and through it both the government and stakeholders, can never be certain that the goals of IRP are being pursued in a way which achieves the maximum benefit for society.

23. CACO does not believe that a legislated IRP would impose a burdensome and complex additional process. On the contrary, CACO believes that a legislated IRP would simplify rate hearings and would allow the OEB to focus on the key issue of achieving the goals of IRP. CACO accpts that

a legislated IRP would add additional costs for the OEB, the LDCs and the stakeholders. CACO believes, however, that those added costs would be present even when DSM measures are pursued within the existing legislation and that the additional costs are justified by the benefits to be achieved through a legislated IRP.

c) A Legislated IRP

24. CACO believes that there are five principal benefits to be obtained through a legislated IRP, as follows:

    1. A legislated IRP would ensure that the integrated resource plans of the individual LDCs are constructed and implemented with the overriding objective of minimum resource cost. It would also ensure that such plans are implemented in a timely fashion. It would also ensure that there was a means of resolving conflicts between various stakeholders in order to ensure that individual IRPs are planned and implemented.

    2. A legislated IRP ensures that a regulatory body like the OEB has the authority to resolve disagreements and to require individual LDCs to take appropriate steps when required. That regulatory body must have the legislative authority to ensure that individual integrated resource plans are in the public interest and that they are being pursued effectively;

    3. A legislated IRP is the only way to ensure that there is an opportunity for public input in a meaningful context. Different stakeholders have different interests in the nature and extent of public participation. The nature and extent of that public participation should not be left to the discretion of the LDCs. Inadequate public participation cannot properly be dealt with in after-the-fact compliance reviews;

    4. A legislated IRP ensures that pursuit of IRP goals is not sidetracked by arguments about jurisdiction;

    5. A legislated IRP reduces the regulatory and therefore, the business and finance uncertainties and risks for the LDCs. In addition, a legislated IRP simplifies and shortens rate approval proceedings.

III THE RECOMMENDATIONS OF THE CACO

25. CACO submits that the OEB should make the following recommendations in its report:

    1. That the legislative framework for a formal IRP be established;

    2. That that legislation require, at a minimum, the following:

        (i) that IRP is a defined term;

(ii) that each LDC file an IRP for a ten year period;

(iii) that each IRP is to include an assessment of all DSM and supply side measures, with a proposal as to which ones are to be followed and which are not, with reasons therefore;

(iv) that prior to and as a condition to the filing of each IRP, each LDC is to consult formally with at least the participants in EBO 169;

(v) that, as a part of that formal consultation, the LDCs are to provide the participants with sufficient data to permit the participants to evaluate independently the accuracy and completeness of each component of the IRP;

(vi) that each IRP be reviewed on a regular basis to assess whether it is meeting its goals, whether changes are required and, if so, what those changes are;

(vii) that interested parties be entitled to participate in the regular, periodic reviews of the IRPs;

(viii) that the OEB be entitled to issue guidelines on aspects of IRP including the design and evaluation of DSM measures and the treatment of their costs. Those guidelines should, to the extent practicable, embody the recommendations in the consensus statements and should be sensitive to the need for incentives for the LDCs to pursue certain DSM measures;

(ix) that the OEB has the authority to approve, disapprove or modify each IRP, including the financial incentives to the LDCs;

(x) that the LDCs may require some financial incentives to achieve the goals of IRP and that, accordingly, the legislation permit the OEB to adopt different approaches to the setting of rates to permit the use of such incentives.

26. Pending the legislative changes, the OEB should issue guidelines on DSM measures. Those guidelines should, at a minimum, do the following:

(i) require the LDCs to prepare a portfolio of DSM measures to be considered at their next rate application;

(ii) require each LDC to include in the portfolio of DSM measures an evaluation of those DSM measures with a proposal as to which ones are to be followed and which are not, with reasons therefore;

(iii) require each LDC to consult with all participants in EBO 169, prior to the filing of the rate application, on the elements of their DSM portfolio;

(iv) require that, as part of that consultation, the LDCs provide participants with sufficient data to enable them to independently evaluate the accuracy and completeness of the DSM portfolio;

(v) that included in the guidelines be guidelines on the design and evaluation of DSM measures and the treatment of the costs of those DSM measures. Those guidelines should reflect, to the extent possible, the recommendations embodied in the consensus statements;

(vi) that intervenor funding be made available for all participants to cover the costs of an independent review of DSM portfolios.

27. CACO, in numbered paragraph 8 hereof has recommended that the OEB issue guidelines to the working group on externalities contemplated by the consensus position on Issue number 3.

28. CACO believes that the consultative process is critical to the success of IRP. CACO believes that, for that process to be successful, funding must be provided to stakeholders. CACO suggests that that funding should be provided under the Intervenor Funding Project Act and should be recoverable by the LDCs in their rates.

EXECUTIVE SUMMARY
OF
THE CONSUMERS' GAS COMPANY LTD.

ISSUE 1 DEMAND-SIDE OPTIONS - COSTING & FORECASTING

The Consumers' Gas Company Ltd. ("Consumers Gas" or the "Company") supports the use of avoided supply-side costs as the basis for costing Demand Side Management ("DSM") programs. Avoided costs should quantitatively include monetized external costs, where available. Relevant, non-monetized external costs should be considered qualitatively.

Demand-side options should be given equal consideration with supply-side options in meeting forecast demand, allowing for appropriate flexibility in both demand- and supply-side plans. The expected results for accepted demand-side programs should be included in the regulatory demand forecast, and thus be reflected in supply-side plans.

ISSUE 2 COST-EFFECTIVENESS TESTS FOR DSM PROGRAMS

Consumers Gas supports the use of several tests to assess the cost-effectiveness of proposed DSM programs. These are:

a) the Societal Cost Test ("SCT"), which includes all quantified costs and benefits of a given program without regard to which parties bear the costs or receive the benefits, and which therefore excludes simple transfers between parties (e.g., customer incentives);

b) the Total Resource Cost Test ("TRCT"), which is equivalent to the SCT without externalities;

c) the Rate Impact Measure Test ("RIM"), or Non-Participant Test, which measures the change in a utility's revenue requirement and the resulting revenue changes due to programs; and

d) the Participant Test, which measures costs and benefits from the perspective of program participants.

The EBO 134 feasibility analysis should be modified to be consistent with the DSM analysis. Thus, for both supply- and demand-side analyses, the SCT would serve as the primary screening, or Stage 1 test. Stage 2 would then consist of the RIM and Participant Tests, designed to address issues of "who pays", cross-subsidization, and program design features such as customer contributions and/or incentives. Qualitative factors would be considered at Stage 3.

Consumers Gas is of the view that EBO 169 is properly constituted to address, and, if appropriate, implement modifications to the EBO 134 analysis.

ISSUE 3 EXTERNALITIES

Consumers Gas supports the inclusion of monetized externalities in the Societal Cost Test. To the extent that relevant externalities remain non-monetized, they should be considered qualitatively when evaluating program cost-effectiveness.

Consumers Gas supports the working group proposal, and is of the view that results will be produced quickly and cost-effectively by pursuing the informal, consultative approach contemplated in that proposal. Consumers Gas is prepared to provide funding for the working group, subject to a budget for its operation being accepted by the Board as eligible for inclusion in its cost of service.

ISSUE 4 INVESTMENTS IN DEMAND-SIDE OPTIONS

The appropriate cost recovery mechanism for the direct costs of DSM programs is one which recognizes the expense and investment nature of the costs.

Specifically, direct DSM program costs should be recovered by: 1) dividing the costs into capital investments and operating expenses, where capital investments are those expenditures with longer-term benefits and operating expenses are those expenditures with shorter-term benefits; 2) recovering the operating expenses through the cost of service, in the year in which they are incurred; 3) treating the capital investment portion of the DSM program costs in a similar manner to traditional rate base components, with the amortization period being the lifetime of the technologies or the period over which the benefits are to be realized; and 4) establishing deferral accounts for DSM operating and capital expenditures, with carrying charges and with disposition of the balances in the next rate period.
This cost recovery mechanism places all resource options, demand-side and supply-side, on an equal footing. It also facilitates the implementation of large scale, cost-effective DSM programs and provides the utility with greater flexibility to respond to a program's success or failure.

ISSUE 5 WHO PAYS?

Customers who are the direct beneficiaries of a program should bear, to the extent possible, the direct financial cost of the program in order to minimize the rate impacts of the program. However, this consideration should be balanced against the objectives of achieving reasonable customer participation rates and other factors such as avoiding lost opportunities. While the overall portfolio of DSM programs should not impose an undue rate impact, a strict 'user-pay' approach would unduly limit the scope and benefits of DSM programs.

Allocation of DSM program costs not recovered from participants should recognize and be proportional to the distribution of program benefits. To the extent that the benefits fall outside of the target group, customers receiving those benefits should bear a commensurate portion of the costs.

ISSUE 6 PART 1: INCENTIVES

In order that the private value to the utilities of pursuing DSM programs be aligned with social objectives, shareholder incentive mechanisms that reward successful implementation of cost-effective DSM should be made available to the utilities. The incentive mechanism must be meaningful to utility shareholders and managers, and to the financial markets, while being fair from a customer perspective.

The incentive mechanism should be tailored to the individual circumstances a utility operates within, and should be flexible enough to accommodate an appropriate range of different DSM program designs and objectives. It should also be performance-based. One appropriate incentive mechanism is the "Shared Savings" approach, whereby a utility would retain a reasonable, yet significant proportion of the net savings arising from a DSM program, subject to the achievement of a threshold level of performance.

The incentive percentages and the associated performance thresholds applicable to differing programs should depend, in part, on the circumstances of the individual utility and the market it serves, the type of DSM program involved, and the difficulty or risk of instituting the program. The performance measures used to determine the amount of the incentive payment for a particular program would be presented to the Board at the same time that the program itself was proposed for approval. These measures would be based on the same estimates of unit program performance that were used to evaluate the cost-effectiveness of the proposed program, and to determine the amount of the distribution margin adjustment, if necessary.

In the case where a program was instituted but did not meet the threshold level of performance, the utility would not be eligible for shareholder incentives, despite the effort and resources devoted to the program, and the net positive savings resulting therefrom. In this circumstance, the failure to earn the incentive payment, in and of itself, constitutes a significant penalty to the utility which utility managers would naturally seek to avoid. Therefore, additional penalties are unnecessary and inappropriate.

ISSUE 6 PART 2: DECOUPLING

Consumers Gas supports partial decoupling as a reasonable and balanced response to the concerns of those who believe that a utility will not aggressively undertake conservation DSM if the existing link between profits and throughput volumes is maintained.

Partial decoupling is a mechanism which specifically and exclusively captures variations in distribution margin, resulting from variations in DSM program performance relative to budget. This is in contrast to full decoupling, which does not distinguish among the factors that operate to cause variances from budget in throughput volumes.

In comparison to full decoupling, partial decoupling would also accomplish the following:

a) it would remove the disincentive created by full decoupling to pursue socially desirable additional sales to existing customers;

b) the potential size of the deferral account balance arising from partial decoupling would likely be less than that under full decoupling, since the focus would be restricted to variances in distribution margin due to variances in the performance of conservation DSM programs and not due to other factors such as weather or the economy;

c) as a result of (b), legitimate concerns with respect to rate variability, particularly for industrial customers, would be addressed;

d) also as a result of (b), risks to both the utilities and the Board would be lessened; and

e) the concerns of parties on both sides of the issue as to how full decoupling would affect utility risk and return on equity would be eliminated.

Partial decoupling and a shareholder incentive mechanism require much the same information, so that partial decoupling does not introduce additional regulatory complexities.

Partial decoupling could and should be symmetrical, so that it applies to situations where the conservation DSM efforts are more successful than forecast and those where the efforts are less successful than forecast. This symmetry would ensure that both customers and the utility are protected.

The disposition of the partial decoupling deferral account balance should be addressed during a rate proceeding. Its disposition must occur independently of the utility's earnings position due to non-DSM related factors, if demand-and supply-side options are to be equally aligned. Also, linking the disposition of the balance to non-DSM factors for which the utility is at risk, would act to maintain the financial disincentive to conservation.

Since partial decoupling seems to offer the optimal resolution to the disincentive issue, its adoption would result in a regulatory principle which could be widely embraced and consistently applied across the utilities by the Board.

ISSUE 7 MEASURING AND MONITORING DSM PROGRAMS

For programs which are determined to be cost-effective, utilities should develop estimates of achievable potential using the best available information from sources such as test marketing, focus groups, and similar programs conducted by the utility or other utilities. Utilities should attempt to maximize achievable potential of cost-effective programs through careful program design and implementation.

The best available point estimates of the volumetric impacts of DSM programs should be incorporated into the demand forecast in order to arrive at a "net" volumetric forecast.

Appropriate measuring and monitoring of DSM programs is necessary to determine their effectiveness and to obtain information used in refining program design. Incremental costs of measuring and monitoring programs must be weighed against the incremental benefits obtained in terms of increased accuracy. While a reasonable degree of accuracy is required, devotion of excessive resources to the monitoring function will impair program cost-effectiveness and inhibit the achievement of real results. As experience is gained, design, implementation, monitoring, and evaluation activities can be refined.

ISSUE 8 MANAGING DEMAND VIA RATE DESIGN ALTERNATIVES

Existing rate design alternatives adequately provide for an enhanced and expanded DSM effort on the part of utilities, and therefore there is no current need to alter existing rate structures. Initial utility DSM efforts should be aimed at implementing effective programs, which might be enhanced at a later stage with potential rate design initiatives. Furthermore, it would be imprudent to institute novel rate design alternatives before gaining substantially more experience, both directly and through monitoring developments in other jurisdictions. Therefore, the management of demand through rate design alternatives should be approached, cautiously and gradually.

Potential rate design initiatives to manage demand must be carefully analyzed to ensure that they will promote desirable objectives and at the same time, satisfy fundamental rate design principles and constraints such as market acceptance. The analysis of any rate design proposal must encompass an examination of competing objectives and the potential impact on the level of a utility's business risk.

ISSUE 9 JURISDICTIONAL CONSTRAINTS TO DSM

The Board has the jurisdiction to approve the test year ratemaking implications of investments and expenditures made by a utility to pursue DSM programs. Further, the Board has the jurisdiction to issue guidelines as to how it intends to evaluate DSM programs for ratemaking purposes within the context of a utility rate case. However, these guidelines cannot fetter the Board's jurisdiction to consider any matter before it, including a departure from the guidelines.

In the opinion of Consumers Gas, there are, however, two areas which will ultimately require legislative attention. They are:

a) whether or not DSM assets are used or useful in the same way as traditional assets; and

b) the longer-term stability of DSM plans, given the nonbinding nature on future Board panels of previous Board panels' decisions.

Without an eventual resolution of these two areas of concern, there is the potential for the appropriateness of previously approved DSM investments to be challenged and for the long-term stability of a DSM plan to be undermined.

It is essential that the utilities and the financial community have complete assurance that DSM assets are on an equal footing with traditional assets in terms of the used or useful standard. Given that the utilities may be required to raise large amounts of capital to fund substantial DSM projects and given that this may be difficult generally, the difficulty could be exacerbated if DSM investments are seen to be open to jurisdictional challenge.

Consumers Gas recognizes that putting amending legislation in place will be a time-consuming process. Therefore in the short term, the Board, the utilities, and all other interested parties can and should proceed with DSM planning and implementation without amending legislation. The Board is urged to use strong language in its EBO 169-III report to indicate its support for these early DSM efforts. However, in the long term, the regulatory concerns enunciated above can only be fully addressed by means of legislation which supports what the Board is adopting as practice. In fact, identifying the exact nature of the required legislation may be well served by a period of actual experience with DSM.

ISSUE 10 IMPLEMENTATION OF IRP

It is the view of Consumers Gas that the Board should proceed with the implementation of expanded DSM as follows.

a) The Board should issue a report with DSM recommendations and guidelines.

b) One of the guidelines would be the expectation that each utility would come forward at its next rate case with DSM programs or plans, the scope of which will be dependent upon the time available to each utility to review the Board's report, consider the guidelines and determine the best approach to implementing them.

c) Further, each utility would undertake meaningful discussion or consultations with representatives of known interested and significantly affected parties, in advance of filing a DSM plan. The purpose of the consultation would be to obtain input from parties so that the DSM programs brought forward by the utility are well targeted, well designed, cost-effective and generally, beneficial from a societal perspective. Effective consultation should tend to ensure a more efficient regulatory process with respect to DSM and a higher prospect of success before the regulator.

d) At a utility specific rate case, the Board would approve the test year impacts of those aspects of the DSM plan which it considered to be just and reasonable, with consideration given to the guidelines issued in EBO 169-III. Ongoing cost recovery would be the subject of future rate cases.

e) Changes in risk (e.g., forecasting, business, regulatory, jurisdictional) arising from the implementation of DSM should be evaluated at the time DSM proposals are made by a utility.

With respect to Integrated Resource Planning ("IRP"), the Board should use its current legislative mandate to the fullest extent possible to pursue the goals of IRP.

Attaining the benefits of IRP, which are predominantly related to DSM, can be fully accommodated within the context of a rate proceeding, both in the short term and in the long term. A full range IRP process, with hearings separate from a rate proceeding, is not necessary. The test year ratemaking implications of a utility's investments and expenditures on DSM can only be approved in a rate proceeding. Therefore, a separate IRP hearing would only add to the complexity and the cost, since to some extent, the examination of certain DSM and IRP issues would have to be repeated in a rate hearing in any case. Separate IRP hearings would also not be conducive to getting on with DSM initiatives in the nearer term.

It cannot be determined now whether further generic hearings on other aspects of IRP will be necessary in order to pursue the goals of IRP. After the first round of DSM plans is considered, it may become apparent whether further generic investigations into supply-side or integration issues are required. The Board should make this determination in consultation with the interested parties.

ISSUE 11 EBO 169 REPORT

In its report, the Board should find that moving forward with DSM programs is in the public interest.

The major elements or issues which must then be addressed by the Board, in order that parties may proceed with DSM, are covered by the ten issues which have been discussed in the EBO 169-II and EBO 169-III proceedings.

If the Board adopts the Consensus Position Statements contained in Exhibit 1.10 and to which Consumers Gas and others are parties, then the guidelines required to move forward with DSM programs will be in place. To a large extent, the Consensus Position Statements are reflected above, in the summary of the Company's position on the ten DSM issues.

There are, however, three particular areas which, in the Company's view, require additional findings by the Board. First, for the reasons summarized above under Issue #6 - Part 2: Decoupling, the Board should find that partial decoupling is a reasonable and balanced resolution to the disincentive issue regarding conservation DSM. Second, the Board should find that in principle, capital investments contemplated in the DSM process are used or useful in serving the public interest. Third, as summarized above under Issue #3, the Board should find that it supports the overall purpose of the working group on externalities and should issue clear guidelines on the timing of the group's reports and on an acceptable approach for financing the operation of the group.

By adopting the principles and guidelines proposed by the Company, the Board will have provided sufficient guidance and direction for parties to continue to work together to advance DSM, and to learn and consequently enhance the DSM process.

OTHER ISSUES AFFILIATE GAS SUPPLY TRANSACTIONS

Neither of Pollution Probe's recommendations on affiliate gas supply transactions are warranted because: 1) affiliate gas supply transactions do not currently represent a substantial proportion of the Company's total requirements; 2) all new supplies are acquired through a public tendering process; 3) the limitations as proposed by Pollution Probe would constrain the Company's future contract negotiations for gas supply; and 4) through the public hearing process, the Board and other interested parties have ample opportunity to review affiliate transactions to ensure that such transactions are not impairing the aggressive pursuit of energy conservation.

EXECUTIVE SUMMARY OF ENERGY PROBE

I. INTRODUCTION

Should Ontario's natural gas customers be allowed to make consumption decisions for themselves, or should they be required to turn decision-making authority over their gas usage to a bureaucratic elite of paternalistic "experts" who claim to know what is best for them?

This is the most important issue facing the Board, and the Board must choose between two vastly different roles for itself: on the one hand, it can decide that Ontarians are incapable of determining how best to meet their energy needs, and disempower the consumer by validating central-planners. If so, it must then permit, or encourage, or even compel the LDCs to subsidize the provision of certain demand-reducing goods and services to some customers with funds collected from other customers. After having made that decision, the Board and the LDCs must commit themselves to a never-ending and, we submit, ultimately fruitless process of conflicting "expert" evidence, argument, regulatory oversight, and monitoring, to determine whether the benefits that were theoretically promised from the subsidies actually materialized, or whether the programs have actually done more harm than good.

On the other hand, the Board can decide to empower the individual gas customer, as it did in its far-sighted 1985 decision to allow residential customers to contract directly for their own gas purchases. If the Board opts to empower the customer, it will work to enhance the free flow of information to customers by encouraging the pursuit of these customers by marketers of both demand-reducing and demand-increasing goods and services that may improve their lives; it will work to further refine the financial accuracy of the price signals these customers receive, so that they will know and consider and incur the true financial costs and benefits of their decisions; it will prod the governments of Ontario and Canada to impose a regime of "green" emissions taxes or of tradable emission rights to incorporate environmental costs into the prices of fuels and all the goods and services made from them; and it will ensure that the LDCs give all due attention to their main mandate -- to provide natural gas and directly related customer-driven services, at least profitable cost, to their customers.

Centrally-planned subsidized DSM programs are characterized by complexity and arbitrariness, by untenable *ceteris paribus* assumptions, by a tendency to equate low gas use with social good, and, ironically, by a tendency to redistribute wealth from poor to rich. Centrally-planned DSM programs are justified by the same philosophies as the well-meaning but largely failed policies of centrally planned economies, and share the untestability of most of their claims, both in advance and after the fact.

ISSUE 1, PART 1 Costing Methodology

There is only one way, in our submission, to reliably calculate the total net value of goods and services to those who receive the goods and services, and that is to measure their willingness to pay a price approaching that total net value. Any alternative, theoretical valuation methods based on untestable or provably false assumptions about "equivalent energy services" or "all other things being equal" or "market barriers" or the like -- especially when confronted with clear evidence of well-informed customers' unwillingness to pay a price approaching the theoretically proposed "total net value" -- must be rejected as unreliable and inaccurate measures of value. Attempts to force customers to support subsidized programs should, in our submission, be categorically rejected by the Board; as the focus group findings in Ex. 14.10 (c) suggest, "universal sharing of costs for conservation programs", as opposed to user pay, was opposed by all members of the group, who "felt quite strongly about their point of view." In any case, inserting these unreliable expert measures of other people's personal value into still more complicated and theoretical formulae to calculate total societal value will merely compound the initial unreliable and inaccurate measurement of value.

Recommendation:

Energy Probe urges the Board to rely on the willingness of well-informed customers to pay for a program as the only reliable measure of the total net value of goods and services to the people who receive those goods and services, and specifically to reject any specious arguments or theories that purport to prove that people receive far higher value from something than they are willing to pay for it.

In our submission, bringing the marginal price of natural gas closer to its marginal financial cost of supply will further inform and empower customers of all kind, and will unavoidably make their own individual "resource plans" result in lower total costs to the system and to society than at present. We submit further that the benefits of improved pricing are generally independent of, and do not conflict with, either the presence or the absence of subsidized DSM programs, or any other matters now being decided by this Board.

Therefore:

Recommendation:

Energy Probe recommends that, whatever the Board should decide on DSM subsidies and other EBO-169 issues, the Board, in conjunction with the LDCs, should take every opportunity to improve the pricing of natural gas in Ontario by making its price as financial-cost-based as practical, whether by time differentiation, or by a further "unbundling" of total gas-system cost components.

Without an accurate assessment of the marginal cost of supplying gas to each group of customers in each time period, none of these calculations can be done accurately, nor can the Board accurately determine the actual rate impact -- and therefore the appropriateness -- of any expense incurred to increase or decrease the demand for natural gas, nor can the avoided cost methodology of the Consensus Statement to Issue #1 be applied, nor can the Total Societal Cost Test recommended in the Consensus Statement to Issue #2 be applied. There is clear evidence that such an accurate assessment of the marginal cost of supplying gas does not now exist, at least in public.

Recommendations:

Energy Probe therefore recommends that the OEB, as a matter of high public-interest priority, require the LDCs to present and defend numerical estimates of the actual ("financial") marginal cost of supplying gas to each group of customers at each time.

Energy Probe further recommends that the results of these calculations be used first and primarily to refine the pricing of natural gas so that its price more accurately reflects its total financial costs to the gas system, and secondly and secondarily as a guide to the cost-effectiveness of the LDCs' demand-altering programs, and third or (better) not at all as a guide to subsidized DSM activities.

The utilities should generally pursue their least-cost option -- as measured by rate impacts for their customers -- when planning to meet their forecast demand. Their forecasters should use any and all techniques and inputs that will improve the accuracy of their results. That would normally include forecasting the demand-reducing ("DSM") activities of their customers, in conjunction with all suppliers of demand-reducing goods and services, including the utilities themselves. The utilities should give similar attention to forecasting the fuel-substituting and demand-increasing activities of their customers, which may well have even larger impacts on load.

ISSUE 2 COST-EFFECTIVENESS TESTS

Due to our concerns about the negative social, equity, and environmental impacts of increasing natural gas prices; and our concerns about the regulatory complexity and arbitrariness of judgments about the actual cost-effectiveness of cross-subsidized measures; and our concerns about the impacts of monopoly-subsidized DSM activities on the non-monopoly suppliers of DSM goods and services), we urge the Board not to encourage or permit DSM activities that are subsidized by revenues from LDC monopoly activities.

It is therefore our submission that the most appropriate cost-effectiveness test is the Rate Impact Measure or "No-Losers" Test which ensures that no customer's conservation benefits are subsidized from another customer's rate increase.

We further submit that the choice of an appropriate cost-effectiveness test, and the corresponding decision under Issue #5 about who should pay, loom especially large in this Hearing precisely because virtually all the evidence indicates little potential for "win-win" gas saving in Ontario -- gas conservation where everybody comes out paying less than under the alternative supply-side alternative.

The market for natural gas in Ontario (while admittedly imperfect, like every other real-world market) is functioning reasonably well. Specifically, this market is apparently not rife with widespread "market failures" that can be overcome with the expertise, credibility, financing, or good program design that is available to LDC experts; the gas market's main "flaw" is to be rife with customers unreceptive to DSM products and services, who can only be induced to buy at below-market prices.

Participants who only participate because of the subsidies -- i.e., who could not be induced to participate by any available (profitable) combination of marketing/information, packaging, financing, or warranties -- are participants whose total expected net increase in value from the measure is lower than the full financial cost of the measure. From a financial perspective (i.e., net of externalized costs), delivering the measure to any and all of these "subsidy-conditional participants" constitutes a net societal cost, not a benefit.

This net societal cost from an individual measure or program cannot logically or conceivably be transformed into a net benefit by expanding it into a "broad menu of demand management programs" designed to appeal to everybody, since the sum of a series of negative numbers will always be a negative number.

Ironically, the only reliable net financial benefit to society from a subsidized DSM measure will be the sum of the net financial benefits of the so-called "free riders" -- the individuals who found enough value in the measure that they were willing (or would have been with better information) to pay its full costs! And, since this benefit could have been achieved without the subsidy -- i.e., at lower or zero cost -- overpaying for it clearly is unlikely to increase societal benefit.

The Board should not adopt the Consensus Statement on this Issue as Board policy because, in our submission, it would provide a flawed and impractical screen for subsidized DSM programs:

n The Societal Cost Test, on which it primarily depends, cannot be reliably applied or tested for accuracy in the presence of subsidized prices. Indeed, applying it requires the correct valuation and summing of all components of a measure's costs and benefits, including the measure's total net value to the people who actually receive the goods and services, which in turn include many cost terms that are typically ignored or "externalized" in the cost-effectiveness calculations done by subsidized DSM planners.

n The four conditions set out in the Consensus Statement under paragraph c) for approving non-sustaining programs which fail the RIM test are variously too vague or weak to have any real value in the selection of programs. It is extremely difficult to forecast -- or even to calculate afterwards -- the "second order costs" of a DSM initiative which raises rates. In fact, they are conceded to be more difficult to forecast than the first round effects.

ISSUE 3 SOCIETAL AND/OR ENVIRONMENTAL EXTERNALITIES

Despite the assurance given by the Consensus Statement that the measure of externalities will be "based on scientifically defensible data", the accuracy of monetized externality values cannot be tested in the absence of a market; hence, the values are essentially arbitrary in their reflection of the economic costs of externalities, and cannot be considered reliable.

A second problem with the consensus approach to externalities arises from trying to internalize the cost of externalities for natural gas in isolation of competing fuel sources. The environmental advantage of natural gas over competing fuel forms is unchallenged at these proceedings. It would not be in the best interest of the environment to burden natural gas with adders that threaten its competitive position, with subsidized DSM programs that will increase natural gas rates. Dr. Ruff refers to this conflict as the problem of "second-best" and explains how,

...even if the price of gas is too low because it does not include all the environmental impacts of gas production and use, it might be that the gas price should be decreased even more ... if other, dirtier energy forms cannot be priced to reflect their external environmental costs.

Recommendations:

4.5 The Board should not try to internalize externalities for natural gas at all unless equal regulatory treatment of more hazardous fuel forms is already enacted.

Given that the Board does not regulate pricing for all competing fuel forms, and is therefore not in a position to internalize externalities across the board, it would be advisable for the Board to work with other regulatory agencies to help establish economically efficient, polluter-pay environmental regulations which can be applied to all sectors, not just the gas sector.

Regardless of which policy instrument is employed to internalize costs, is most important that it is applied broadly across the economy and reflects those costs in the price of all fuel forms.

Recommendations:

The Board should recommend that the Government of Ontario urge the federal government to internalize environmental externalities for energy/fuel use in Canada in the near future, through the introduction of emissions charges and/or tradable emissions permits. Should the federal government fail to act quickly, the Ontario government should take all steps possible to internalize environmental externalities for energy/fuel use in Ontario in the near future, through the introduction of emissions charges and/or tradable emissions permits.

ISSUE 4 INVESTMENTS IN DEMAND SIDE OPTIONS

DSM investments should be recovered in a business-like way from the proceeds of those investments, preferably by fence-ringed, non-regulated, DSM businesses. As Dr. Ruff noted, separating DSM activities from a utility's gas supply business will protect customers from possible rate impacts due to the implementation of financially unsustainable programs.

Recommendation

Investments in demand side options should be recovered from the proceeds of those investments.

The public is well served by regulation only in those areas, such as natural monopolies, where it cannot protect itself. Any area which can be efficiently removed from the regulatory system should be set free, to enable willing consumers to control those aspects of the gas system which can be unbundled and made competitive.

The business of supplying DSM products is not a natural monopoly, rather it is an inherently decentralized activity.

Recommendation

Demand side management should be a deregulated activity.

The Board should ensure that the demand side and supply side activities are accounted for on an equal basis in the sense that no activities should be permitted for rate making purposes which generate less revenues than costs. Neither the LDCs nor the Board should consider giveaways or subsidies to be assets.

Recommendation

The Board should not permit rate basing of non-utility-owned facilities.

Mr. Gibbons, on behalf of Pollution Probe, suggested that the Board might disallow imprudently allowed costs. The threat of cost disallowance will provide the LDCs with an incentive to design successful programs and will act as a brake on what might otherwise be recklessly wasteful programs.

Recommendation

The Board should maintain the option of disallowance of LDC DSM costs in the future if the expected benefits do not materialize.

The Board should ensure that consumers are informed about their contributions to conservation program subsidies. Dr. Ruff notes that, "The quasi-market type of program suggested here would at least give consumers the information, incentive and opportunity they need to complain if they feel they are not getting their money's worth -- which may be why DSM advocates almost universally oppose telling consumers how much they are paying for DSM."

Recommendation

Should the Board permit subsidized DSM, gas utilities should be required to indicate individual customer contributions to the subsidy on each customer's bill.

ISSUE 5 SHOULD "USER PAY" PRINCIPLES APPLY TO DSM PROGRAMS?

The Board should endorse the principle of individual user pay and ensure that profits from DSM businesses do not subsidize gas rates (and therefore gas consumption) by directing DSM profits to DSM businesses.

Recommendation:

The principle of individual user pay should apply to DSM programs within the practical limits of cost allocation.

ISSUE 6 SHOULD UTILITIES RECEIVE DSM INCENTIVES?

DSM program costs should not be regulated or rate based and therefore should not receive a higher regulated rate of return than returns on investments in monopoly supply services.

The Board should reject the suggestion that increased conservation of natural gas requires removing from rate design the profit incentive to increase throughput volumes.

Recommendation:

The benefits of decoupling should be achieved by way of a further unbundling of gas services and rates so that customer costs, capacity costs, and commodity costs are priced separately on a user pay basis.

ISSUE 8 MANAGING DEMAND THROUGH RATE DESIGN

Customers should be charged separately for capacity charges (disaggregated by season and time as much as practical), customer charges, commodity charges, and DSM charges within the practical limits of the cost allocation process. The benefits of this approach include economic efficiency, total resource (not just gas) conservation and efficiency, and maximization of customer information, range of choice, and both the right to profit from, and the responsibility to pay for, the full financial consequences of his or her activities.

Rate design should pass useful information to the consumer about the costs created by the consumer's actions, not make moral judgments about appliance choices. Instituting gas-service surcharges to fund so-called "socially beneficial" subsidized DSM programs is a move away from the proper role of rate design.

Recommendations:

The Board should manage demand by promoting, wherever feasible, the unbundling of all gas products and services.

The Board should eschew rate design alternatives unrelated to the market cost of service.

ISSUE 9 JURISDICTIONAL CONSTRAINTS

To protect the fairness of the IRP deliberations, demand side and supply side initiatives must receive equal treatment.

Recommendations:

If the Board wishes to adopt Energy Probe's preferred recommendation, that utility DSM activities be removed from the utility's regulated monopoly operations and be undertaken by unregulated, for-profit, spinoff DSM businesses, it should feel free to proceed. The Board's current jurisdiction is sufficient.

If the Board wishes to adopt Energy Probe's second-best recommendation, that Ontario's LDC's be guided by the principles of user-pay and rate minimization when designing and implementing DSM programs within their regulated operations (in a manner similar to the treatment of their appliance sales and rental businesses), it should feel free to proceed. The Board's current jurisdiction is sufficient.

If the Board wishes to adopt the October 9, 1992 Consensus Statements on the demand side Issues List, the Board must ensure that supply and demand side options are subject to equal, symmetrical treatment in the regulatory process; hence, the Board should hesitate until getting a clear legislated mandate to do so.

With respect to the issue of DSM subsidies, it is important to consider not only the Board's jurisdictional constraints in allowing them, but more importantly, whether or not in allowing them, the Board is attempting to fulfill a societal function outside its mandate.

Recommendation:

Energy Probe recommends that the Board leave the function of optimizing social welfare to the government who has a prescribed mandate to carry out this function and concentrate its own efforts on consumer protection.

ISSUE 10 IRP: IS THERE A NEXT STEP?

Energy Probe submits that centrally planned IRP which contemplates the implementation of subsidized DSM programs is unlikely to serve the public interest. However, we do not want the Board to reject the concept of integrated resource planning or to forsake regulatory actions which can enhance beneficial forms of planning.

Recommendations:

Energy Probe recommends that the Board proceed with IRP by encouraging the LDCs to implement non-regulated, for-profit, spinoff DSM businesses.

If the Board chooses not to adopt Energy Probe's recommendation for spinoff DSM businesses, Energy Probe recommends that the LDCs be guided by the principle of user-pay when developing DSM programs within their regulated operations.

ISSUE 11 DEVELOPMENT AND SUBMISSION OF DSM PLANS

ISSUE 12 OTHER ISSUES

Recommendation:

Energy Probe recommends that the Board amend its E.B.O. 134 Cost-Effectiveness Test for supply-side investments to make it more difficult to justify rate-increasing, financially non-sustaining (i.e., subsidized) investments, at least to the extent of correcting criticisms noted by Pollution Probe in points 1-3 in Exhibit 8.1, pp. 14-15, "Flaws of the E.B.O. 134 Cost-Effectiveness Test", and as elaborated in Mr. Gibbons's testimony at TR pp. 3161-4.

EXECUTIVE SUMMARY OF THE KITCHENER GAS DISTRIBUTION UTILITY

Kitchener recommends Board guidelines to emphasize demand side measures in the operations of the Ontario gas utilities, along the following lines.

ISSUE 1

Costing Methodology

1. Kitchener does not fully accept the consensus statement on this issue because it ignores the direct financial costs associated with any proposed demand side/supply side project and it requires consideration of all avoided costs and benefits. Kitchener submits that there are some social benefits which incidentally result from a demand side investment, which, as argued under Issue 2, should not be used to justify investment.

The Role of DSM in Utility Operations and the Forecasting of Demand

2. Kitchener submits that the effects of the utilities' DSM portfolios should be fully factored into the utilities' forecast of demand and the approach contemplated by the four paragraphs of the second part of Issue 1 should be endorsed by the Board. In the result, it can be expected that the utilities will demonstrate, at the next rate hearing, that they have placed greater emphasis on the DSM side of their operation. On the other hand the Board should recognize the limits, in practical terms, to the potential scope of DSM activities. However, if a DSM option is costed equally or less than the supply side option, then of course, the Board should expect that the DSM will prevail.

ISSUE 2

Screening and Approval Stages

1. The Board should approve the staged screening and approval process outlined in the consensus statement.

Undue Rate Impact

2. The Board should recognize in its decision that the question of undue rate impacts cannot be determined in a generic hearing and that acceptability of rate impacts will depend on the circumstances which exist at the time of the rate case. Accordingly, no definition as to what constitutes "undue rate impacts" should be issued by the Board.

Inclusion/Exclusion of Externalities

3. Kitchener disagrees with the consensus statement under Issues 1, 2 and 3 which assume that all environmental and social externalities of an investment should be considered in the cost/benefit analysis. In its guideline as to the selection of externalities which can be used by the utilities to justify an uneconomic investment, the Board should instruct them to disregard those externalities which do not fall within the ambit of the utilities mandate or responsibilities. It is recognized that the utility is responsible for all of the social and environmental consequences of its projects. However it should also be recognized that it is not responsible for all the benefits which flow incidentally from its investments. In particular it is not responsible for the creation of tax revenues to government or employment wages in the community. These may result from investment, but the utilities should not be able to obtain revenues from rate payers for investments which require these factors to be taken into account in order to obtain the Board's approval. In other words, regulation is a surrogate for competition, not government; and therefore it should not require rate payers to finance uneconomic projects because they meet governmental objectives. Similarly, the utilities should not be allowed to justify their investment in uneconomic projects because they will reduce the energy costs of prospective customers. Unregulated companies do not make investments for this purpose and therefore regulation should not force the rate payers to bear this burden.

4. Accordingly, Kitchener submits that the principles of E.B.O. 134 should not be endorsed for application to demand side investments insofar as they permit utilities to justify investment on the basis of incidental benefits such as taxes to government, increased employment wages to the community and energy savings to prospective customers. The investment policies of E.B.O. 134 have the effect of approving investment for reasons which fall outside of the requirement to provide utility services on an economic basis. Also they result in unnecessary investment, in terms of utility services, and hence encourage an inefficient use of resources in fundamental contradiction of I.R.P. principles.

ISSUE 3

Working Group

1. The Board should recognize that the working group has a continuing and useful role to play for the purposes of compiling and organizing the literature on monetization and determining the range of monetized values as evidenced by the literature. The Board cannot reasonably expect the working group to reach a consensus on the monetized value and therefore this task should be excluded from the working group's mandate.

2. The working group membership should be scaled down so as to permit representation, without duplication, of the environmental groups, customers and native peoples.

ISSUE 5

The Degree of Subsidization

1. The Board should be willing to entertain DSM programs that result in subsidization within classes and between classes of customers. Accordingly, the Board should be willing to accept proposals for portfolios which are not self-sufficient. The problem with portfolio self-sufficiency is that it confines the burden of subsidization to those who engage in DSM activities. In practical terms this will mean that the purchasers and renters of high efficiency equipment, a program which yields a return above the awarded return, will support all of the other programs. This in turn will tend to discourage participation in the self-supporting program by making it more expensive than otherwise.

Incentives to Participants

2. It is recognized that incentives may be very difficult to justify and that indeed incentives in the form of "giveaways" and "life-line" rates may be counter-productive in IRP terms. The fact remains, however, that situations can exist where incentives are useful. Accordingly, Kitchener submits that the appropriateness of any incentive must fall to be determined on a program-by-program basis in the rate hearings.

Cost Allocation

3. The cost of DSM programs should be allocated on the basis of their causal relationship, where possible, by following the basic cost allocation principles which determine the allocation of supply side cost. In addition, the Board should not allow utilities to pass the costs of their DSM programs on to other utilities, which have DSM responsibilities of their own.

ISSUE 6 - PART I

Incentives to the Utilities

1. Kitchener submits that the Board should not be willing to entertain proposals for "shared savings" or other mechanisms by which revenues depend on a systems of penalties and rewards geared to the success of the DSM activity. The reasons for this position can be summarized as follows. Shared savings do not fall within the formula for revenue recovery in s.19 of the **Act**; the relative success of a program may not be known for a number of years and a system of rewards and penalties would discourage the introduction of worthwhile investments or the premature discontinuation of a program before its potential was fairly determined; also, the relative performance of a program may not necessarily indicate the competence level of management; finally, it is submitted that the nature of regulation itself works against the use of a shared savings mechanism for ensuring efficiency. Regulation can pass judgment on a company proposal but it cannot, apart from flagrant dereliction, second guess (and in that sense assume) the management of company operations.

2. It is also noted that compensation by way of incentive is unnecessary because of the existence, under regulation, of the very strong incentive to expansion of investment. Accordingly, the most effective way to induce utilities to allocate a fair share of their investment capital to demand side measures is to curtail current supply side spending by restricting it to projects which can be justified by reference to the utilities service, social and environmental responsibilities and reject projects which can only obtain approval if the Board permits consideration of benefits which fall outside of the utilities' responsibility.

3. On the other hand some incentive type features, not involving revenue compensation, should be allowed. In particular, the Board should favourably entertain proposals designed to reduce the risk of not earning the allowed return including proposals for a deferral account and a multi-year expenditure commitment.

<u>**Decoupling**</u>

4. Decoupling represents a significant and fundamental change in the way utilities are regulated. Accordingly, it should not be forced on the utilities unless the evidence in favour of such a step is sufficiently strong to warrant such a fundamental change. In the circumstances here it is submitted that the evidence is not sufficient weighted in favour of a forced decoupling.

5. In addition, in Ontario, one utility intends to introduce a decoupling measure and the other two do not. This will permit the Board to observe the effects of decoupling in an almost laboratory type setting. By comparing the two approaches, the Board will be in a far better position to access them than if decoupling was forced on all three utilities at the same time.

6. Accordingly, Kitchener submits that the Board should express its willingness to entertain a decoupling proposal but should not mandate it.

ISSUE 7

1. Kitchener supports the expectations expressed in the consensus statement under this issue and would only add that the Board should require the utilities to formalize a process for the sharing of research and development activities required to obtain the identification of the best possible portfolio. In this respect Kitchener asks that the collaborating group of utilities be required to report to the Board at rate hearings on the results of their work so that the parties and the Board can make an assessment, of their own, as to the extent of DSM programming worthy of consideration.

ISSUE 9

<u>**The Board's Jurisdiction**</u>

1. The Board should not recommend an alteration of its jurisdiction at this stage, but rather should adopt the assumptions in the consensus statement under this issue as the basis on which to proceed with the introduction of IRP.

2. In addition it is submitted that the Board should recognize that in rate cases it may be necessary to give multi-year commitments to some DSM expenditures. In this it is not suggested that future panels be bound by such commitments; however it is suggested that the Board should be willing to approve a program for a number of years unless, at an intervening rate hearing, circumstances arise which warrant a reconsideration of the original long term approval.

ISSUE 10

Level of Investment

1. While the Board can expect the level of DSM investment to be increased in the future, it should be recognized that there are a number of limiting factors. First there was no suggestion at the hearing that there were types of DSM programs which a utility had ignored. Accordingly, the parties should not be surprised if the portfolios presented at the next rate cases contain programs similar to those which currently exist. Secondly, the initiative in the gas industry will be limited by the degree of IRP exhibited in other fuels. If all fuel prices do not reflect the cost of externalities to some degree, then the more harmful environmental fuels will prevail.

Consultation to Improve Program Design

2. Subject to the role to be given to the working group under Issue 3, it is submitted that the development of DSM programs should remain the responsibility of the utilities. Accordingly, the requirement of consultation referred to in paragraph 3 of the consensus statement should not become a formal component of rate case preparation. The initiative and responsibility for developing programs of any kind, including DSM proposals, must necessarily reside with management. Consultation should be seen as part of the ongoing responsibilities of the market research departments in each utility, it should not be regarded as a condition precedent to the formulation of plans.

EXECUTIVE SUMMARY OF ONTARIO METIS AND ABORIGINAL ASSOCIATION

The Ontario Metis and Aboriginal Association (OMAA) fully supports the adoption of Gas Integrated Resource Planning (IRP) in Ontario. Such a process can provide benefits to the members of OMAA and society as a whole. However, the implementation of an IRP process presents difficult challenges. OMAA believes that the benefits of integrated resource planning can best be achieved through a comprehensive planning process which takes into account the concerns of various affected parties, and guarantees their full participation.

OMAA has a number of specific concerns regarding the integrated resource planning process. These relate to the valuation and incorporation of externalities into the planning process, the regulatory authority of the Board to implement an IRP process, the format in which IRP will be considered, equity concerns relating to the implementation of demand-side management (DSM) programs and low-income ratepayers, the level of consultation with affected parties, and the availability of funding.

OMAA members may be greatly affected by externalities related to the production, transmission, and consumption of natural gas. OMAA is therefore concerned that the identification and valuation of such externalities is performed adequately. Of particular concern is the issue of externalities which are difficult to quantify and monetize. In such instances, the qualitative treatment in the planning process must be meaningful. OMAA's members should be consulted on this matter, since they offer a unique expertise which can assist in this process.

OMAA is concerned that the Board's current regulatory authority is insufficient for the development of a comprehensive IRP process. Under the Board's present mandate, the IRP process as implemented may fall short of securing all of the benefits that may be attainable through a more comprehensive process.

Nonetheless, in the absence of broader authority, the IRP process should be developed to the extent possible. While not as complete or beneficial as it might be, this process would still provide substantial benefits to society. In proceeding, it is important that the Board establish a regulatory environment which provides very clear signals to the participants, and which provides an adequate level of incentives to promote the utilities' participation.

Rate case hearings have been suggested as the appropriate adjudicatory forum for the IRP process. Such a forum would be limiting for two reasons. First, OMAA would be practically and financially unable to participate in each individual rate hearing. Second, OMAA is concerned that insufficient attention will be paid to the IRP process in the midst of the numerous competing priorities normally inherent in rate case hearings.

In addition, the issue of equity must be carefully considered in the planning and implementation of DSM programs. While the majority of OMAA's members are not gas users, some of its members who do use gas are low- or fixed-income ratepayers. The IRP process must make a concerted effort to ensure that such individuals can participate in DSM programs.

OMAA is also concerned about its ability to meaningfully participate in the development of the integrated resource planning process. OMAA's members are likely to be significantly affected by the outcome of this process, and can contribute a unique expertise and perspective to assist in its development. However, OMAA does not itself have the resources to ensure that its concerns will be considered in the IRP process. At present it is uncertain whether meaningful consultation will actually take place in the development of the IRP process. OMAA's concerns in this regard are illustrated by the experience to date with the Externality Working Group. While OMAA was invited to participate in this Group, such participation has been effectively foreclosed by lack of financial support.

The IRP process should involve meaningful consultation with all affected parties. OMAA suggests that consultation should occur on three levels. First, the Board and gas utilities should make a special effort to understand OMAA's concerns and orientation. This outcome would be greatly facilitated by consultation at the community level. Second, OMAA members who are gas users should be consulted in the development and implementation of DSM programs, just as other groups of consumers are consulted. Third, the Board should establish a meaningful process for consultation with OMAA members regarding the identification and valuation of social and environmental externalities. This should occur with the input of affected communities.

Finally, for the IRP process to be effective, sufficient funding must be provided for consultation, as well as legal and expert support of affected parties. Such consultation and support is necessary to ensure that the integrated resource planning process is comprehensive, effective, and equitable, thereby maximizing the potential benefits to Ontario society.

EXECUTIVE SUMMARY OF POLLUTION PROBE

ISSUE 1 GENERAL ROLE OF DSM

Pollution Probe supports the consensus position statement on Issue #1.

ISSUE 2 COST-EFFECTIVENESS TEST

Pollution Probe supports the consensus position statement on Issue #2.

ISSUE 3 EXTERNALITIES

Pollution Probe supports the consensus position statement on Issue #3.

ISSUE 4 DSM INVESTMENTS

Pollution Probe supports the consensus position statement on Issue #4.

ISSUE 5 WHO SHOULD PAY?

Pollution Probe supports the consensus position statement on Issue #5.

ISSUE 6 Part 1 INCENTIVES AND PENALTIES

Pollution Probe supports the consensus position statement on Issue #6 Part 1.

Issue 6 Part 2(a) DECOUPLING

COUPLING AND THE PENALTY FOR CONSERVATION

For many years the O.E.B. has held that the primary function of Ontario's gas utilities should be to sell and/or distribute natural gas. Therefore it is not surprising that the Board adopted rate making principles that link or couple the gas utilities' profits to their natural gas throughput volumes. That is, under the O.E.B.'s status quo rules, the higher are the utilities' throughput volumes, the higher are their profits and conversely, the lower the volumes, the lower the profits. This is true whether or not throughput volumes are above or below forecast levels.

However, one effect of coupling the utilities' profits to their throughput volumes is that a utility is financially penalized if it promotes conservation, since a conservation measure by definition reduces throughput volumes, and therefore profits, from what they otherwise would have been.

DECOUPLING--ELIMINATING THE PENALTY FOR CONSERVATION

In his classic text, Principles of Public Utility Rates, James Bonbright stated that regulation should not penalize utilities for acting in accordance with the public interest:

> "...rate regulation...should at least take pains to avoid rules or rate making that positively penalize stockholders for efficient or otherwise desirable action by management."

There are two main reasons why Bonbright's admonition against penalties is applicable to coupling throughput volumes and profits. These reasons suggest that the rate making principle of coupling should be replaced by a decoupled regime.

1. Penalizing Conservation Conflicts With Government Policy

   Penalizing a utility for promoting conservation is inconsistent with Government of Ontario policy. As the Deputy Minister of Energy stated in his February 28, 1992 letter to the O.E.B.:

   > "The Government of Ontario strongly supports demand side planning by all energy utilities. Conservation is the priority in meeting energy needs in Ontario"

2. Penalizing Conservation Conflicts With IRP

   The purpose of IRP is to meet customers' energy service needs by the least cost mix of supply side and demand side (energy conservation and energy efficiency) options. As the consensus statement on Issue #1 has noted:

   > "In terms of meeting future demand, DSM options should be given equal consideration as supply-side actions"

   If DSM options should be given equal consideration with supply side options, it is irrational to penalize a utility when it promotes conservation. As the National Association of Regulatory Utility Commissioners has stated:

   > "Reduced earnings to utilities from relying more upon demand-side resources is a serious impediment to the implementation of least-cost planning and to the achievement of a more energy-efficient society."

3. The Importance of Removing The Penalty

As noted by NARUC, above, the penalty for conservation is "a serious impediment" to important public interest objectives. According to a joint statement of the Natural Resources Defense Council and the Pacific Gas and Electric Company (the largest investor-owned utility in the U.S.), the California Public Utility Commission's decision to decouple profits and throughput volumes was an essential prerequisite for PG&E's renewed commitment to energy efficiency programmes.

> "The first step in improving the regulatory system, therefore, is to decouple net revenues and profits from total sales. This step was taken in California beginning in the late 1970s, and it has been essential to PG&E's renewed commitment to efficiency programs."

The general importance of using financial self-interest to encourage conservation is recognized by, for example, Union Gas. Mr. van der Woerd has stressed the importance of relying on market mechanisms to achieve energy efficiency goals:

> "And our position would be that if it [conserving energy] is done using the market mechanism, we will get a lot farther in achieving that goal than if we do it in a manner which will require more regulation, more scrutiny, more non-productive activities in the marketplace, other than simply conserving energy and using it more efficiently.
>
> And what we're suggesting is that if we use market mechanisms wherever possible, as this government also endorses in the same policy statement, then we will be able to get on with this subject quickly."

Finally, it is worth noting that Ms. Peverett of Centra Gas conceded that the O.E.B.'s status quo rules which couple utility profits and throughput volumes motivates a utility to sell gas:

> "Q. All right. Ms. Peverett, does Centra believe that there is an inherent bias in the rate making process which encourages utilities to sell more gas rather than less gas?
>
> A. I think it's fair to say that utilities in the short-term are motivated to sell more gas."

OBJECTIONS TO DECOUPLING

1. Decoupling Will Lead to Undue Rate Variability

According to Centra Gas, decoupling is not in the public interest because it will lead to undue variability in the rates of its large volume industrial customers.

It is Pollution Probe's submission that the evidence does not support Centra's assertion.

If decoupling had been in existence in 1991, the 1991 debit balance in Centra's decoupling deferral account would have been $11,088,100. Furthermore, according to Exhibit 14.6(a), if the debit balance was allocated amongst Centra's rate classes in proportion to their share of Centra's rate base, the temporary decoupling-related rate increases would have been:

Residential Rate 1 customers	4.2%
Commercial Rate 1 customers	4.8%
Commercial Rate 10 customers	2.4%
Industrial Rate 20 and 25 customers	0.47% to .87%

Moreover, the evidence before the Board indicates that the magnitude of an annual Centra decoupling deferral balance would typically be much lower than $11 million. According to Mr. Oosterbaan of Centra Gas, if decoupling had been in place in the past, the deferral account debit for 1990 would be only $4.1 million. Furthermore, in 1988 and 1989 the deferral account would have had credits of $3.6 million and $5.3 million respectively.

Thus if decoupling had been introduced in the past and if Centra amortized the deferral account balances over a three year period, the temporary rate impact would be 70% less than the impact shown in Exhibit 14.6(a). That is, the rate impacts would be:

Residential Rate 1 customers	1.26%
Commercial Rate 1 customers	1.44%
Commercial Rate 10 customers	0.72%
Industrial Rate 20 and 25 customers	0.14% to 0.26%

It is Pollution Probe's submission that temporary rate impacts of the above noted magnitude will not impose an undue burden on Centra's customers. Furthermore, to put these temporary rate variations into context, it is important to note that:

1. if Centra's throughput volume forecasting methodology is unbiased, Centra's customers will experience temporary rate reductions as often as they will experience temporary rate increases;

2. by reducing Centra's cost of equity, decoupling will ensure that, on average, Centra's rates will be lower than they would be in the absence of decoupling; and

3. any decoupling-related rate variations will be small in relation to the rate variations that have been historically experienced by Centra's customers (e.g., in 1987 a typical 100% load factor Rate 20 customer experienced a 31% rate increase).

Furthermore, with respect to fuel switching, it is Pollution Probe's submission that a firm large volume industrial customer will not leave Centra's system because of a temporary rate increase of 0.14% to 0.26%.

It is also Pollution Probe's submission that it is very unlikely that a large volume interruptible industrial customer will go off gas because of a temporary rate increase of 0.14% to 0.26%. Moreover, if a large volume interruptible customer is about to leave the system because of a temporary rate increase of the above noted magnitude, Centra could retain the customer by renegotiating the customer's range rate.

Finally, it is important to note that if a decoupling-related temporary rate increase of 0.14% to 0.26% would cause an industrial customer to go off gas; parity of reasoning implies that a similar decoupling-related decrease in gas rates would cause an equal increase in gas consumption.

Thus, on balance, there is no reason to believe that decoupling-related rate variations would lead to a net long term reduction in natural gas consumption.

2. If Decoupling Is Adopted Gas Utilities Will Not Have Sufficient Incentive To Promote Fuel Switching

According to Dr. Bower, a witness called on behalf of Centra Gas and Union Gas, if decoupling is adopted, gas utilities will not have sufficient incentive to promote fuel switching.

It is Pollution Probe's submission that Dr. Bower's assertion is not persuasive for the following reasons.

First, under Pollution Probe's Formula B decoupling proposal, a utility's revenues would be linked to its number of customers. That is, under Pollution Probe's proposal, a utility can increase its revenues by increasing its number of customers.

Second, under a decoupling regime, it will still be in a utility's long run financial self-interest to increase its number of customers and the number of gas end-uses per customer because these activities will lead to increased utility rate base. As the Board is aware, everything else being equal, the greater is a utility's rate base, the greater are its profits.

Third, under a decoupling regime, it will still be in a utility's long run financial self-interest to increase its number of customers and the number of gas end-uses per customer because these activities will lead to increased natural gas throughput volumes. Everything else being equal, higher throughput volumes imply lower rates. Moreover, lower rates are in the self-interest of utility shareholders for at least two reasons:

1. by making natural gas more competitive, lower rates will increase the probability that the utility will be able to earn a fair rate of return on its investment; and

2. lower rates will lead to increased natural gas sales and hence increased utility rate base and profits.

In light of the above and other evidence, it is Pollution Probe's submission that Ontario's gas utilities will continue to aggressively promote fuel switching to natural gas if the O.E.B. decouples the link between profits and throughput volumes.

However, if the O.E.B. believes that there would be insufficient incentive for gas utilities to promote fuel switching if their profits are linked to their number of customers, as opposed to their throughput volumes, there are a number of remedies available to the Board. First, it could approve a decoupling mechanism that links a utility's revenues to its number of customers and the number of gas end-uses per customer.

Second, it could establish a deferral account with respect to a utility's operating and capital costs of promoting and implementing fuel switching (i.e., a fuel switching expenditures deferral account similar to the DSM expenditures deferral account proposed in the consensus position statement on Issue #4).

Third, the Board could establish financial bonuses for utilities that aggressively and cost-effectively increase the number of socially cost-effective gas end-uses per customer.

3. A DSM Lost Revenue Adjustment Mechanism (LRAM) Is Superior To Decoupling

According to the three gas utilities a DSM lost revenue adjustment mechanism (LRAM) is a superior mechanism to eliminate the penalty for promoting conservation. An LRAM is an accounting mechanism which, in theory, would sever the link between a utility's profits and changes in its throughput volumes due to its DSM programmes. Moreover, if an LRAM is implemented a utility's profits would still be a function of throughput volume fluctuations that are due to unforecast changes in the business cycle, unforecast changes in alternative fuel prices and the weather.

It is Pollution Probe's submission that an LRAM is <u>not</u> superior to decoupling for the following reasons:

1. In practice, an LRAM cannot completely remove the financial penalty for promoting conservation;

2. An LRAM will unnecessarily increase the cost of making conservation a utility's most profitable course of action. That is, an LRAM will needlessly enrich utility shareholders at the expense of utility customers; and

3. An LRAM will increase regulatory costs.

<u>An LRAM Cannot Remove The Penalty For Promoting Conservation</u>

In practice an LRAM cannot completely remove the financial penalty for promoting conservation for at least two reasons.

First, for some conservation options (e.g., public information programmes, rate reform) it is impossible to measure their impact on utility throughput volumes and revenues. Thus an LRAM would not be able to remove the financial penalty for the successful implementation of these options.

Second, for the remaining DSM options it is impossible to measure with a satisfactory degree of precision their impact on a utility's throughput volumes and revenues. As a consequence, assuming an LRAM, a utility's O.E.B.-approved lost revenues will be either greater or less than its actual DSM-related lost revenues; whereas under decoupling the utility's actual DSM-related (and other) lost revenues will be returned to the utility.

Thus, assuming an LRAM, the probability of full recovery of DSM-related lost revenues will be less than the probability of full recovery of throughput volume related revenues. In short, under an LRAM, a utility's risk minimizing strategy will be to aggressively promote sales, not conservation.

An LRAM Will Unnecessarily Increase The Cost of Making Conservation A Utility's Most Profitable Course Of Action

Pollution Probe, Centra Gas, Consumers' Gas, Union Gas and others have endorsed the consensus position statement with respect to Issue #6 - Part 1. That is, Pollution Probe and the gas utilities are in favour of shared savings incentives for utilities that successfully implement cost-effective DSM programmes.

However, if the O.E.B. approves shared savings incentives and an LRAM it will have established a contradictory set of utility incentives. A shared savings incentive and an LRAM would be mutually inconsistent because:

1. a shared savings incentive rewards a utility for conserving energy; and
2. an LRAM maintains the status quo financial bonus for exceeding the O.E.B.-approved throughput volume forecast.

The creation of contradictory incentives will increase the cost of making conservation a utility's most profitable course of action. As Exhibit 13.4 demonstrates, if an LRAM maintains a 50 basis point reward for a 1% increase in throughput volumes, the shared savings and LRAM incentives for reducing throughput volumes by 1% must be at least 51 basis points if conservation is to be the utility's most profitable course of action. On the other hand, if the link between a utility's profits and its throughput volumes is decoupled, conservation will be a utility's most profitable course of action if the shared savings incentive is only 1 basis point. Thus, using the numbers chosen as examples in Exhibit 13.4, an LRAM increases the cost of making conservation a utility's most profitable course of action by 50 basis points.

In short, an LRAM will enrich utility shareholders at the expense of utility ratepayers.

An LRAM Will Increase Regulatory Costs

As noted above, it is impossible to precisely measure the impact of DSM measures on a utility's throughput volumes. As a consequence it is reasonable to assume that if an LRAM is established, many hearing days will be devoted to adversarial cross-examination of utility, Board Staff and intervenor expert witnesses with respect to exactly how much energy was saved by utility DSM programmes.

Lengthy and acrimonious debates on the appropriate magnitude of a utility's LRAM account balance are not in the public interest, assuming the existence of a simpler and less contentious solution (decoupling), for at least two reasons.

First, it would needlessly increase the direct financial cost of regulation to the ratepayers.

Second, it will tend to embitter the relationship between the utilities, Board Staff and other intervenors. As a consequence, it will reduce the ability/willingness of these parties to resolve other DSM matters in a constructive and cooperative manner.

CONCLUSION

In order to make the O.E.B.'s rate making principles consistent with Government of Ontario policy and the principles of IRP, the O.E.B. should decouple the link between a utility's profits and its throughput volumes.

Thus it is Pollution Probe's respectful submission that the O.E.B. should adopt the majority consensus position statement on decoupling. That is:

> "1) Decoupling of profits and throughput volumes should be introduced to remove the existing disincentive to aggressive pursuit and implementation of cost-effective conservation DSM programs.
>
> 2) Decoupling mechanisms should recognize, and be tailored to, individual utility operating conditions, markets, and other circumstances. Individual utilities should propose specifics of a decoupling mechanism best suited to their respective circumstances. The proposal should be brought forward in the context of a rate case."

As the Board is aware, the above quoted consensus position statement is supported by Board Staff, the City of Toronto, the Coalition of Environmental Groups, the Consumers' Association of Canada (Ontario), the Ontario Metis and Aboriginal Association and Pollution Probe.

ISSUE 7 MEASURING DSM

Pollution Probe supports the consensus position statement on Issue #7.

ISSUE 8 RATE DESIGN

Pollution Probe supports the consensus position statement on Issue #8.

ISSUE 9 JURISDICTION

Pollution Probe supports the consensus position statement on Issue #9.

ISSUE 10 IMPLEMENTATION

Pollution Probe supports the following consensus position statements on Issue #10: Part 1, Part 2(b) and Part 2(c).

ISSUE 11 THE BOARD'S REPORT

The Board has invited comments addressing 1) issues which should be addressed in its report, and 2) specific guidelines which should be provided in its report.

It is Pollution Probe's respectful submission that it is not necessary for the Board to provide in its report a lengthy and detailed review of the issues, or specific guidelines, in the event that the Board chooses to rely on the consensus statements, since the statements are relatively well understood.

While the Board's report need not be lengthy or detailed, Pollution Probe submits that it is crucial that the report clearly state the direction the Board favours. An ambiguous or ambivalent position is not likely to provide adequate guidance to the parties.

AFFILIATE GAS SUPPLY TRANSACTIONS

If a utility purchases gas from an affiliate then, everything else being equal, the aggressive promotion of energy efficiency by the utility will lead to a reduction in its affiliate gas purchases. Furthermore, everything else being equal, a fall in affiliate gas purchases will entail lower profits for its affiliate and controlling shareholder.

Thus it is Pollution Probe's submission that new affiliate gas supply transactions should be banned in order to ensure that the aggressive pursuit of energy conservation will not be contrary to the financial self-interest of the controlling shareholders of Centra Gas, Consumers' Gas and Union Gas.

If the Board does not wish to ban all new affiliate gas supply transactions, it is Pollution Probe's recommendation that the Board state that all new affiliate gas supply transactions should have a "no displacement" clause. That is, the utility must not be able to reduce its gas purchases from its affiliate suppliers if the utility's requirements decline. A "no displacement" clause would be in the public interest because it would ensure that the aggressive promotion of energy conservation by a utility would not reduce the short run profits of its affiliate gas supplier(s) and its parent corporation.

In this context it is worth noting that Consumers' Gas does not have the right to reduce its gas purchases from its affiliate supplier, Telesis Oil and Gas, if its gas requirements decline.

Furthermore, it is Pollution Probe's submission that a ban on new affiliate gas supply transactions is unlikely to lead to a rise in a utility's gas costs for two reasons:

1) the gas reserves of the affiliates of Ontario's gas utilities are a very small percentage of Canada's total gas reserves; and

2) Ontario's gas utilities have a tendency to structure affiliate transactions so as to benefit the affiliate at the expense of the ratepayer.

In other words, it is Pollution Probe's submission that a ban on new affiliate gas supply transactions is more likely to lower utility gas costs than to raise them.

EXECUTIVE SUMMARY OF THE CITY OF TORONTO

In accordance with the Board's Procedural Order No. 4 herein dated December 7, 1992, the City of Toronto hereby submits its Executive Summary of its argument in this matter. This Executive Summary firstly sets out the City's submissions in respect of Issues 1 through 11; secondly summarizes the City's position; and thirdly reiterates the City's requests of this Board.

CITY OF TORONTO COUNCIL'S POSITION ON ISSUES DESCRIBED IN THE OEB'S DEMAND-SIDE ISSUES LIST AND ISSUE 11

City of Toronto Council presented no evidence in support of matters related to Issues 1 to 10 at the hearing, but solely takes the following positions as set out in Exhibit 10.4, pp.50-57. It also takes the following position related to Issue 11:

Issue	Position
1.	As per paragraphs 1, 3 and 6 in the Consensus Statement. No position taken on the other paragraphs.
2.	No position
3.	As per the Consensus Statement.
4.	No position.
5.	No position.
6. Part 1	As per the Consensus Statement.
6. Part 2a	As per the Consensus Statement of Board Staff, et al. Not in agreement with Centra's/Union's Consensus Statement.
7.	As per paragraphs 2, 3, 6 and 8 in the Consensus Statement. No position taken on the other paragraphs.
8.	No position.
9.	No position.

10. Part 1 As per paragraphs 1, 2, 3 and 4 in the Consensus Statement of Board Staff et al. No position taken in respect of paragraph 5.

10. Part 2(a) No position.

10.Part 2(b) No position.

10.Part 2(c) No position.

11.

It is respectfully submitted that the Board should address the issue of **need.** In other words, the Board should make findings on why these DSM plans are necessary. In support thereof, the City refers to the uncontradicted written evidence of Dr. Danny Harvey, as supported by his vice voce testimony on November 27, 1992, which is summarized as follows:

As a result of human activities the concentrations of greenhouse gases have increased, leading to a strengthening of the greenhouse effect. There is no scientific doubt that such strengthening will lead to a warmer climate, although there is uncertainty concerning the amount and rates of warming, the regional distribution of precipitation and soil moisture changes, and the full impact of these changes.

Scientific concern over human emissions of greenhouse gases is based on the following:

- human activities have already caused greenhouse gas concentration increases;
- much larger greenhouse gas concentration increases will occur if present trends continue;
- significant and potentially catastrophic climatic changes will likely result in many regions from the greenhouse gas concentration increases projected for business-as-usual scenarios;
- rates of climatic change will likely be such as to pose severe stresses on natural ecosystems, even for changes which,, were they to occur slowly, would be beneficial;
- time lags of up to several decades will occur between greenhouse gas increases and the climatic and ecosystem response, so that adoption of a wait-and-see approach will mean that human societies will be committed to significantly greater changes by the time that unambiguous impacts begin to be felt; and
- such changes as do occur will be irreversible for all practical purposes.

Under business-as-usual scenarios, greenhouse gas concentrations will continue to increase beyond the end of the next century, leading to global warming and ecosystem responses for hundreds of years. Initial impacts could therefore be quite different from later impacts but, overall, the risk of negative impact will increase the longer that greenhouse gas concentrations are allowed to increase. Impacts expected in Canada will relate to agriculture, forestry, water resources, natural habitats, fisheries and sea level increases.

The extraction, processing, transportation and end use of natural gas result in emissions of both carbon dioxide and methane. Per unit of energy, natural gas releases the smallest amount of carbon dioxide of any fossil fuel, and shifting from oil and coal use to natural gas could be an important and effective method of reducing carbon dioxide and in some cases methane emissions. It is therefore important that every effort be made to use natural gas as efficiently as possible if greenhouse gas emissions are to be reduced by the magnitude required, on a global basis, for atmospheric stabilization. DSM plans should therefore be developed and submitted by the utilities to the Board.

Furthermore, Canada is a signatory to the United Nations Framework Convention on Global Climate Change, which Convention has not yet been ratified by Parliament or Cabinet. By requiring the development and submission of DSM plans by the utilities, the Board would be in part implementing the intent of Articles 3.1 and 3.3 of this Convention.

II. CITY'S POSITIONS

1. The City of Toronto submits that there is scientific evidence which supports this Board deciding that DSM plans should be developed and submitted by the utilities; so as to assist in the protection and maintenance of the human and natural environments and to reduce greenhouse gas emissions.

   1.0.1 The City further submits, based at least on the City's evidence, that there is a need for such plans, given that:

   (a) global warming in all likelihood will create significant detrimental economic and environmental effects in Canada during at least the next century;

   (b) global warming is largely caused by a build-up of greenhouse gases, including Co_2 and CH_4;

   (c) an appreciable volume of greenhouse gas emissions are from the LDC's systems; and

   (d) this Board and the LDC's are in a position to reduce these emissions through IRP, without negatively impacting fuel switching initiatives or the LDC's shareholders.

4. The City further submits that the City's specific requests, as hereafter described in Section III of this Executive Summary can be fulfilled by the adoption of a number of the Technical Conference Consensus Statements.

III. CITY'S REQUESTS

The City of Toronto respectfully requests that this Board:

(a) call for the development and submission of IRP plans by the utilities;

(b) find that there is a need for such plans given the need to reduce greenhouse gas emissions as soon as possible;

(c) adopt ratemaking mechanisms which will allow and encourage Consumers' Gas to reduce carbon emissions associated with natural gas consumption in the City of Toronto and elsewhere by 20%, relative to the 1988 level by the-year 2005, through improved end use efficiency;

(d) find that the mandate of Consumers' Gas' should include the aggressive promotion of energy efficiency and conservation in addition to its service role as a natural gas distributor;

(e) establish ratemaking mechanisms which will ensure that the aggressive promotion of energy efficiency and conservation by Consumers' Gas is in the interest of Consumers' shareholders; and

(f) find that Consumers' Gas be allowed and encouraged to finance research, development and commercialization of technologies with higher efficiencies in the use of natural gas than are available at present.

EXECUTIVE SUMMARY OF UNION GAS LIMITED

I. INTRODUCTION

Union emphasized its strong support for the goals of IRP and the pursuit of new DSM measures to promote conservation and efficiency, as Union regards DSM as an essential part of its overall mission and its commitment to its customers to provide cost-effective, energy efficient and environmentally sound energy products and services.

Union pointed out that ultimately, the measure of success in the pursuit of conservation and efficiency would be customer attitudes and decisions. It therefore emphasized the need for consultation with its customers in planning DSM initiatives, and for pursuing the most cost-effective opportunities to promote the wise use of natural gas.

Union cautioned against transplanting the DSM experience of the electrical utility industry into the context of Ontario gas utilities. It drew attention to the significant differences in typical avoided costs in the two industries, as well as other points of distinction, and accordingly submitted that the U.S. Electric industry approach based on "give-aways" or financial incentives to encourage participation which might be cost-effective in the electric utility context would be far less likely to be appropriate and cost-effective if implemented by Ontario gas utilities.

Union referred to its own previous experience and success in the area of DSM. It emphasized the need to look to that and other relevant experience, as well as employing common sense, in order to avoid actions which, though seemingly attractive in theory, may have unforeseen and undesirable consequences. Union stated that its previous experience and analysis of potential programs underscored the importance of focussing on customers and on overcoming market barriers to wise energy use through customer value and choice.

Union pointed out that, consistent with the declared policy of the Ontario Government, the promotion of energy efficiency and conservation involved not only reducing gas use per application, but also providing for the wider availability of gas and its greater use in new efficient applications and in substitution for other more environmentally harmful fuels. Union noted that there was far greater potential for achieving environmental benefits through encouraging the substitution of gas for other fuels than through reducing gas use per application.

ISSUE 1 (COSTING METHODOLOGY)

Union endorsed the consensus statement on this issue, but observed, that its own avoided costs for typical DSM conservation measures are relatively low for reasons specific to it. Union therefor submitted that proposed DSM measures should be examined in light of each utility's particular circumstances, rather than in the context of a "one size fits all" approach.

Union recognized the importance of identifying avoided costs in evaluating DSM options and ensuring that they receive the same consideration in meeting demand as distribution supply side options. Union also pointed out, however, that demand side options differ fundamentally from supply side options in that the former are targeted to provide special benefits for distinct customer groups, rather than to ensure a consistent level of service for all distribution customers. As a result, Union cautioned that equal consideration of demand and supply side options does not mean giving identical weight to identical sets of public interest considerations.

Union expressed its intention to consider as many DSM opportunities as possible and to develop the most comprehensive portfolio of DSM measures as would be practical, consistent with its portfolio approach to demand side management.

ISSUE 2 (COST-EFFECTIVENESS TESTS)

Union endorsed the consensus statement on this issue and submitted that the most important principle underlying the tests to be applied to determine the desirability of DSM programs, was the need to ensure that all considerations concerning societal, customer and participant impacts are included, and that the same methodology is used to assess both different types of DSM options and supply side options.

Union strongly disagreed with suggestions made by others that rate impacts due to DSM (which would occur when the rate impacts of DSM exceed the rate impacts of the avoided supply options) are of little or no consequence. Union noted that these suggestions were contradicted by actual experience and other data concerning customer behaviour, and that they ignored the environmental benefits to be achieved by enhancing the competitive position of gas and promoting its use in additional wise applications. It also observed that since new DSM programs would benefit targeted customer segments, rate impacts could influence customer perceptions of the overall fairness of the programs, thereby affecting customer response. Union explained in Reply that its desire to develop a portfolio of DSM programs with no overall rate impact over the life of the project was based on sound principles.

ISSUE 3 (EXTERNALITIES)

Union endorsed the consensus in principle but submitted that in order to take proper account of social and environmental externalities, both the costs and benefits of supply side and demand side options must be considered and given the appropriate weight. Union cautioned that it was seemingly impossible, and certainly undesirable, to attempt to reduce that exercise to the application of mathematical formulae. Union noted the difficulties involved in trying to monetize externalities, and urged that judgment had to be exercised in attempting to compare the value of monetized externalities to economic costs determined by market transactions.

Union shared the concern raised by Energy Probe and others that in attempting to monetize environmental externalities, care must be taken to avoid gas-only monetization in a way that makes gas appear less attractive than more environmentally detrimental fuels, simply because gas is regulated. Union pointed out that the environmental and other benefits resulting from the wise use of gas are enormous in comparison to the benefits associated with attempting to reduce the use of gas.

Union recommended that the working group contemplated in the consensus statements be limited to participants in EBO 169, with the addition of a government representative if desired, and that it be given a specific mandate to prepare a timely report indicating the extent to which the parties can agree upon the externalities to be considered, their measurable impacts, monetized values and the methodologies to be employed. Union also recommended, in order to maximize the efficiency of the process, that any required consulting experts be retained by the group as a whole, to be paid for by the three LDCs.

ISSUE 4 (DSM INVESTMENTS)

Union endorsed the consensus statement on this issue, Union supported the establishment of deferral accounts for DSM capital and operating expenditures in order to provide equal treatment to demand and supply side expenditures. Union submitted that demand side "investments" must be amortized and included in rate base, and made subject to an investor return, in the same way as costs associated with the construction of new facilities. It also noted that DSM initiatives presented significant forecasting risks substantially beyond Union's control, and submitted that the deferral accounts were appropriate, in part to help remove potential disincentives relating to forecasting risks, as well as regulatory risks.

ISSUE 5 (WHO SHOULD PAY FOR DSM PROGRAMS)

Consistent with the consensus statement which Union endorsed, the cost of DSM programs should be borne, to the extent possible, by the direct beneficiaries of those programs. Union submitted that the use of a DSM portfolio approach would be appropriate so that financially self-sustaining programs could support DSM programs which were not self-sustaining.

Union strongly disagreed with basing DSM programs on "give-aways" or excessively large financial incentives, on the grounds that for a gas utility in Union's circumstances, those would lead to adverse rate impacts, undesirable cross-subsidization and unfair competition with other suppliers of goods and services. Union also rejected as illusory, and financially foolish, suggestions that such problems could be overcome by providing "something for everyone", and argued that this approach would only exacerbate the problems, particularly in Union's circumstances given its existing base of DSM activities participation and relatively low avoided costs.

ISSUE 6 (Part 1) (INCENTIVES)

Union endorsed the consensus statement on this part of the issue.

Union submitted that in order to eliminate any potential disincentives to demand side programs and ensure equal treatment for demand side and supply side options, several matters needed to be addressed. The first was the need to provide a mechanism to trace DSM investment costs between rate cases in a deferral account to be amortized and included in cost of service for the purpose of recovery through future rates. Union recommended that there be a carrying cost associated with the deferral account comparable to the utilities' overall rate of return. The second matter was the need for the utilities to have the necessary confidence that, as a matter of principle, prudently incurred DSM costs recorded in deferral accounts, together with adequate financing costs, would be recoverable in rates. Union indicated that it would be satisfactory if the Board's Report in this case included an appropriate declaration of principle and recognition of the need for adherence to such principle by future panels of the Board.

Union submitted that as long as a DSM portfolio is cost-effective, and the utility has the opportunity to earn its allowed rate of return through both demand and supply side investments, no further bonuses would be necessary at this time. Union noted that the design and implementation of bonus mechanisms would be fraught with difficulties and would likely result in significant burdens, including administrative and regulatory burdens.

ISSUE 6 (Part 2) (DECOUPLING)

Union endorsed the consensus statement of Union and Centra regarding decoupling.

Union submitted that decoupling was far too blunt an instrument to deal with the matter of potential unforecasted lost revenues between rate cases, and that the implications and likely adverse impacts of decoupling were out of all proportion to the magnitude of the potential lost revenue problem intended to be addressed.

Union noted that inasmuch as the promotion of energy conservation included efforts to increase the efficient use of gas, and given the opportunity to have regular rate cases and to set rates based on forecasted DSM efforts, the overall concern regarding lost revenues between rate cases was likely to be modest. Union emphasised that it does not consider that without decoupling, it has been financially penalized or discouraged to date from promoting conservation and efficiency which it explained is fundamental to the pursuit of its customer and corporate goals in the 1990's.

Union acknowledged that there might be specific circumstances in which unplanned or unforecasted DSM opportunities between rate cases would raise a lost revenue concern, but submitted that other more appropriate mechanisms should be made available to resolve any such potential barrier to DSM. Union referred in that regard to alternatives such as a formal lost revenue adjustment mechanism, or a more program specific accounting order mechanism which most other regulators have adopted to deal with DSM related lost revenue concerns.

Union submitted that by contrast to these alternatives, decoupling would present a number of significant problems. Union argued that a major problem with decoupling was that it would eliminate an incentive to promote the socially beneficial use of gas, and thus undermine a major element of Ontario's energy policy objectives. Union also commented on other likely adverse impacts of decoupling, including the potential for distortion of utility decision making and perverse price signals, added regulatory complexity, negative effects on competitive gas markets and unacceptably large price swings for significant industrial customers.

Union strongly objected to suggestions that support for decoupling could be viewed as a reflection of a utility's, or a regulator's, commitment to conservation. Union pointed out that the majority of Electric utilities and virtually all gas utilities that have aggressively pursued DSM are doing so without decoupling.

Union asked the Board to confirm in its Report that it would, if necessary to allow the pursuit of new DSM opportunities, accommodate utility specific regimes which would involve specific accounting orders and the subsequent disposition of the lost revenue related accounting balances subject to the standard tests of prudency.

ISSUE 7 (DSM POTENTIAL)

Union submitted that since DSM depended upon consumer acceptance, it was far more important to focus on examining "achievable potential" (through consultation, reviewing information regarding other utilities and market research), rather than conducting theoretical and costly studies of "technical potential". Subject to this concern, and comments about the problems of end use forecasting, Union endorsed the consensus statement.

ISSUE 8 (RATE DESIGN)

Union endorsed the consensus statement on this issue. Union submitted that rate design is a relatively weak tool to promote conservation, and that it is far more important to address the market barriers to wise energy use where there is substantially greater opportunities to promote conservation and sufficiency. Union indicated that it considered the existing M2 rate structure for residential consumers to represent an appropriate balance between competing rate design objectives. Union agreed that it was important to provide customers with information concerning their consumption patterns and resulting cost.

ISSUE 9 (JURISDICTION)

Union endorsed the consensus statement on this issue. Union referred to a portion of the consensus statement addressing the need for consistency on the part of the Board and for an expression by the Board of its support for longer term DSM programs proposed by utilities in rate cases. Recognizing the potentially large new DSM investments and related risks, Union asked the Board for a firm endorsement of that aspect of the consensus statement.

ISSUE 10 (Part 1) (IMPLEMENTATION)

Union endorsed the consensus statement regarding this aspect of Issue No. 10.

Union observed that the scope and detail of formal DSM plans is likely to evolve over future rate cases as more information regarding avoided costs, market barriers and customer research becomes available. While recognizing the value of meaningful discussions with known interested parties, Union noted that the most important assessments to be made with respect to successful DSM relate to Union's customers.

Union proposed, consistent with its approach to supply side programs, that it would provide funding where appropriate to facilitate participation by interested parties in the consultative process relating to DSM, and seek the recovery of forecasted costs in future rate cases. Union asked for the Board's endorsement of this approach.

ISSUE 10 (Part 2(a) (IMPLEMENTATION)

Union endorsed the consensus statement for this aspect of Issue No. 10 notwithstanding it's belief that future generic hearings on supply side integration matters will not be required. Union expressed the view that current regulatory processes, utility planning capabilities and appropriate consultation create ample opportunities to evaluate supply side alternatives. It noted further that the major elements of IRP with respect to integration of plans will also be in place through the process of estimating avoided costs and employing those estimates in DSM program evaluation. Union indicated, however, that subsequent workshops might be beneficial.

ISSUE 10 (Part 2(b)) (IMPLEMENTATION)

Union rejected the consensus statement on this aspect of Issue No. 10.

Union did not support the further formalization of IRP through legislative measures as a necessary precondition to the pursuit of DSM or the goals of IRP. Union submitted that no need or justification had been shown for such additional regulatory complexity or the substantial cost that would result, particularly in view of the LDCs' support for virtually all of the important provisions of the consensus statement and for the goals of IRP.

ISSUE 11 (GUIDELINES)

Union submitted that the Board should address all of the issues set forth in the consensus statement. Union commended to the Board the guidelines discussed in the consensus statement under the issues endorsed in Union's argument, together with certain clarifications identified in Union's argument. Union submitted that the guidelines should be sufficiently flexible to allow each utility to pursue DSM in light of its own particular circumstances, and to recognize that DSM is evolving and should be permitted to develop based on experience.

GLOSSARY OF TERMS

Achievable Potential - An estimate of the amount of energy savings that reasonably can be expected to result from the implementation of a DSM program or plan, taking account of such factors as market acceptance and economics. (see also **Technical Potential**)

Administrative Costs - Expenses incurred by a utility for program planning, design, management and administration. These costs include general overhead costs required to implement a program, but do not include direct program costs such as marketing, purchasing, incentives, monitoring and evaluation costs.

Average Costs - A natural gas utility's total costs divided by its total throughput, expressed as the cost per unit of volume, or as the cost per unit of energy.

Avoided Cost - The total supply-side costs that are not incurred, or deferred into the future, as a result of the implementation of a DSM program. Avoided costs are usually taken to be the full marginal or incremental costs of supply that will be avoided.

Balancing Account - An account established by a utility, with regulatory approval, to record differences between estimated and actual charges (or credits) relating to a current accounting period; for disposition in a future accounting period or periods. Also referred to as a **Deferral Account.**

Base Case Forecast - The anticipated natural gas demand in the absence of additional DSM programs. In this Report, the base case forecast includes all of the utility's DSM programs to date and its NGV efforts.

Base Load - The minimum continuous load over a given period of time. Excludes peak demand.

Break-Even Analysis - Analysis of the costs and benefits of a DSM program to define the level at which the benefits from a program will just cover the costs.

BTU Tax - A tax on energy sources, including non-fossil fuels, based on their heating values.

Carbon Dioxide - The gaseous product of the complete combustion of carbon. The chemical formula for carbon dioxide is CO_2.

Carbon Tax - A tax on fossil fuels usually in proportion to the carbon dioxide they emit when fully combusted. Sometimes used as synonym for **BTU tax.**

Collaborative - A balanced, manageable and diverse group of parties formed to assist in utility planning processes. In this Report, the Collaborative assists the Ontario natural gas utilities with the selection, qualitative assessment, measurement and, if possible, monetization of externalities.

Conservation Programs - Programs aimed at increasing the efficiency of energy use, thereby reducing consumption.

Cost Award - An amount of money payable by one party to another as directed by the Board in relation to a proceeding before the Board.

Cost-Based Rates - Rates which recover the costs of providing a particular service. These rates may differ from Cost-Related Rates, which are less strictly based on cost causality.

Cost-Effectiveness Tests - Tests which compare the costs and the benefits of a program. Such tests include the Societal Cost Test, the Total Resource Cost Test, the Rate Impact Measure Test, the Utility Test, and the Participant Test.

Cost-of-Control Method - An evaluation method, used to assign values to externalities, which utilizes the cost of controlling the generation of the externality as a proxy for the cost of the damage which results from the externality. (Also see **Damage Costing**)

Cost-Related Rates - Rates that reflect cost causality but may recognize risk and other factors, such as rate stability and value of service.

Cream-skimming - (pejorative) A DSM strategy which involves the implementation of only the least costly, most profitable or most readily implementable programs.

Cross-subsidization - Financial subsidies obtained from one customer or customer group to pay all or a portion of the costs for a program, service or facility used by a different customer or customer group.

Customer Class - A group of customers with similar characteristics, such as economic activity or demand level, typically served under the same rate schedule.

Customer Incentive - Cash or non-cash payment offered to customers to encourage participation in a DSM program.

Damage Costing - An evaluation method used to estimate the value of an externality based on an estimate of the damage caused by the externality. (Also see **Cost-of-Control Method**)

Declining Block Rates - A rate structure that has two or more successive rate steps where the unit price of each level declines as energy consumption increases.

Decoupling - A ratemaking mechanism or incentive which eliminates the link between profits and sales volume, so that a utility will not suffer a profit reduction if it implements a DSM program which results in an unforecast reduction in sales revenue.

Deferral Account - An account established by a utility, with regulatory approval, to record differences between estimated and actual charges (or credits) relating to a current accounting period; for disposition in a future accounting period or periods. Also referred to as a **Balancing Account.**

Demand-Side Management (DSM) - Actions taken by a utility or other agency which are expected to influence the amount or timing of a customer's energy consumption.

Demand-Side Options - Load management techniques a utility can use to reduce or alter its load profile, such as energy efficiency improvements and load shifting.

Discounted Cash Flow (DCF) Analysis - A financial evaluation methodology that accounts for the time value of money through the application of an appropriate discount rate to a project's forecast costs and benefits/revenues. Typically used for long-term projects.

DSM Activity/Measure - An action taken by customers to alter the amount or timing of their energy consumption.

DSM Plan - A strategic plan which sets objectives for, and directs and controls the implementation, monitoring and improvement of a utility's preferred DSM portfolio.

DSM Portfolio - A group of DSM programs which have been selected and combined in order to achieve the objectives of a utility's DSM plan.

DSM Program - An organized collection of related DSM activities or measures which a utility may use to affect the amount and timing of a customer's energy consumption.

DSM Strategy - The combination of a portfolio of DSM programs and its implementation plan which a utility intends to employ in order to achieve its DSM objectives.

E.B.O. 134 - A generic hearing by the Ontario Energy Board in 1987 to review the issue of natural gas system expansions in Ontario, during which tests for determining the economic feasibility of such expansions were recommended.

Embedded Costs - The sum of a utility's costs related to its fixed assets and/or long-term debt of different vintages. Assets are valued at their installed cost less depreciation without adjustment for inflation or changes in market values.

Emissions Trading - A pollution control mechanism by which a regulator or government attempts to restrict undesirable emissions in a certain area by setting an upper limit or cap on the total discharge of a pollutant for a region. Clearance to emit a limited quantity of the offending substance is then granted to existing and potential polluters, who are permitted to sell these rights in an open market.

End-Use Forecasting - Load forecasting relying primarily on end-use models to extrapolate historical use per customer patterns under different economic and market assumptions.

End-Use Model - A "grass-roots" approach to estimating a customer's energy consumption, which focusses mainly on the type and efficiency of an end-user's equipment. These models require relatively large amounts of detailed data.

Energy Service Company (ESCO) - An organization that contracts with energy users, landlords and/or utilities to evaluate, design, install and monitor capital and operating improvements in an existing building facility or industrial process, to reduce energy and operating costs over a contract period. ESCOs typically finance the costs of these improvements and receive payment by sharing in the resultant energy and operating savings.

Energy Services

1. (End-User) The comfort, lifestyle or industrial production capability an end-user obtains through the use of an energy form.

2. (Utility) The storage, transmission and distribution of natural gas and any other services provided by the utility as part of the delivery of natural gas to its customers.

Environmental Externalities - Costs and benefits which result from changes to the environment as a direct or indirect result of a company's or individual's actions, but which are not accounted for as business costs or benefits.

Environmental Impact - The effect of any change imposed on the ecology of an area due to some action.

Expensed - The accounting process by which a utility's costs are charged in the current period against current revenues and proposed for recovery as a cost of service to the ratepayers.

Externalities - A general term encompassing **Social Externalities** and **Environmental Externalities**.

Filing Requirement - Information that a utility or other applicant is required by the Board to present as part of its evidence in a rates hearing or other proceeding.

First Round Costs and Benefits - The direct effects of a DSM program, portfolio or plan.

Fixed Costs - Costs that remain relatively constant and do not tend to vary with throughput. For example, interest expense, depreciation charges and property taxes. (Also see **Variable Costs)**

Free Riders - Customers who would have adopted program-recommended action even without program incentives, but who participate directly in the program when it is offered and claim the benefits of any incentive or subsidy.

Fuel-Switching Programs - Measures or activities which encourage customers to change from one fuel or energy form to an alternate fuel or energy form.

Global warming - The possible warming of the earth due in part to human activities.

Grandfathering - Exempting an existing activity or condition from compliance with a new policy or regulation.

Greenhouse Effect - The theory that the earth's atmosphere is changing as a result of the buildup of gaseous emissions, such as carbon dioxide and methane, due to natural causes and human activity, and thereby inhibiting the earth's ability to dissipate its heat.

Incentive - See **Customer Incentive** or **Utility Incentive.**

Incremental Cost - The cost of supplying one additional unit of energy. Also called **Marginal Cost.**

Incremental Participation - The number of additional participants in a DSM program compared to a previous time frame or an alternative circumstance.

Industrial Sector - The group of non-residential, non-commercial customers that provide products, including agriculture, construction, mining, and manufactured goods and services.

Integrated Resource Planning (IRP) - A planning method for use by natural gas and electric utilities whereby expected demand for energy services is met by the least costly mix of demand-side and supply-side programs and strategies. Sometimes referred to as **Least-Cost Planning.**

Integration Phase - A future phase of the E.B.O. 169 IRP proceedings which will consider how to combine the demand-side and supply-side aspects of planning in order to ensure the consistent treatment of both aspects in the development of a utility's integrated resource plan.

Inter-class subsidization - Financial subsidies obtained from one customer class to pay for a program, service or facility used by a different customer class whose own contributions are insufficient to completely finance the program, service or facility.

Interruptible Rates - Rates, typically involving discounts, offered to customers in return for the utility's right to curtail deliveries of an energy form for a specified duration, subject to mutually agreed-upon conditions.

Intervenor Funding Project Act (IFP Act) - Ontario legislation which provides for the awarding of funding, in advance of the commencement of a hearing, for interventions before selected tribunals, including the Ontario Energy Board.

Internalization - Accounting for the costs and/or benefits that are related to, or result from, the activities of an individual or enterprise, but which previously have not been accounted for in the cost of doing business.

Intra-class subsidization - Financial subsidies obtained from a customer or customers in a particular customer class to pay for a program, service or facility used by a different customer or customers in the same customer class whose own contributions are insufficient to finance the program, service or facility.

Inverted Rates - A rate structure with two or more successive steps where the unit price of each level increases as consumption increases.

Iterative Process - A process in which some or all steps in a normal progression may be repeated as more knowledge or information is gained.

Least Cost Planning - A synonym for Integrated Resource Planning.

Load - The amount of natural gas consumed by a particular customer, group of customers, or all the utility's customers.

Load Factor - The average consumption of natural gas over a designated period expressed as a percentage of the peak or maximum consumption during that same period.

Load Profile - The demand for a utility's energy supply or the amount of consumption by a particular customer or group of customers displayed over time to illustrate consumption patterns during a specified period.

Local Distribution Company (LDC) - A natural gas utility which sells and/or delivers gas to end users in a specific franchise area or areas.

Lost Opportunity - An occasion to improve the efficient use of energy which is foregone when a decision is based only on short-term or immediate benefits and does not consider long-term cost impacts, e.g. not adding insulation during a renovation.

Lost Revenue Adjustment Mechanism (LRAM) - A technique which allows the utility to recover, in its rates, the revenue loss associated with a specific DSM program or set of programs. (See also **Revenue Adjustment Mechanism**)

Marginal Cost - The incremental cost of supplying one additional unit of energy.

Market Barrier/Imperfection - A factor which prevents a market from arriving at an efficient equilibrium price which would result from matching supply with demand.

Methane - a colourless hydrocarbon gas which is the chief component of natural gas. Its chemical formula is CH_4.

Monetization - Assigning a dollar value to the effect of an externality for use in planning processes.

Net Rate Impact - The overall change in the customer's per unit cost of an energy form due to the introduction of a proposed DSM program, portfolio or plan.

Net Societal Benefit - The aggregate impact on society of an activity, taking into account all effects on the economy, environment and society (both quantitative and qualitative).

NGV Programs - Gas utility programs aimed at promoting the use of natural gas as a vehicle fuel.

"No Regrets" Approach - A policy which includes actions to be undertaken that may mitigate the potential adverse effects of a future event (e.g. global warming) for which the severity and timing of occurrence are uncertain.

Partial Decoupling - A technique which weakens the linkage between profits and unforecast reductions in revenue due to a DSM program. For example, a Lost Revenue Adjustment Mechanism.

Participant Test - An evaluation of the costs and benefits of a DSM program to determine the total financial effect that the program will have on the end users that partake in the program.

Participation Rate - The ratio of the number of actual program participants to the total number of participants eligible to partake in the program.

Payback Period - The time required for a program to generate sufficient revenue or cost savings to recover the costs of developing and implementing the program.

Peak Demand - The maximum amount of natural gas required by a customer or LDC over a given, usually short, period of time.

Penalty - A regulatory mechanism that disciplines a utility for not achieving a specified target.

Penetration - A measure of the level of customer acceptance or market share for a particular service, product or program.

Penetration Rate - A measure of the level of customer acceptance or market share for a particular service, product or program, expressed relative to the total potential market.

Pilot Programs - A trial or experimental program to test customer acceptance and program potential, before deciding whether to commit to the full implementation of a DSM program.

Planning Horizon

1. The time required for the full achievement and/or cost of recovery of a demand-side or supply-side plan.
2. The forecast useful life of a DSM program.
3. A pre-determined outpost year for the forecasting, monitoring or duration of a program, portfolio or plan.

Polluter-Pay - The principle which requires that those who are the source or cause of pollutants pay their proportionate share of the societal cost of the damage caused by the pollution.

Program Effect - The net change in energy demand of a participating customer or group of customers that can be attributed to a DSM program.

Qualitative Assessment - An evaluation of the costs and/or benefits of an event or activity in non-numeric or non-monetized terms.

Quantification - The process by which numeric values are assigned to the costs and/or benefits of an event or activity.

Rate Impact Measure (RIM) Test - A screening test which measures the impact of a DSM program on the customer's unit cost of energy.

Retrofit - The modification of existing equipment or of a current facility, typically to improve energy efficiency.

Revenue Adjustment Mechanism - A usually symmetric technique which allows the utility to include, in its rates, the revenue loss or gain associated with a specific DSM program or set of programs. (See also **Lost Revenue Adjustment Mechanism**)

Screening Process - The application of cost-effectiveness tests to select the most appropriate DSM programs and portfolio.

Seasonal Rates - Service rates offered by a utility to recognize changing operating conditions and costs during different times of the year.

Second Round Costs and Benefits - The indirect effects of a DSM activity or measure.

Sensitivity Analysis - The variation of an input or assumption to determine how the expected output of an analysis will respond, and to identify which of the variables and assumptions are most determinant of the expected output. For example, testing the response of DSM program savings to pessimistic, optimistic and most likely natural gas price forecasts.

Shared Savings Mechanism

1. A regulatory incentive to the utility's shareholders whereby they are allowed to retain a portion of the net dollar benefit from a DSM program or set of programs.

2. An arrangement whereby an Energy Service Company (ESCO) finances a DSM activity in return for a portion of the savings that are generated.

Significance - That quality of a factor or effect which is considered important or of consequence and therefore, worthy of further consideration.

Social Externalities - Costs and/or benefits, which affect the well-being or lifestyle of segments of the public as a direct result of a company's or individual's activities, but which are not accounted for as a cost of doing business.

Social Impact - The effect of any change imposed on the well-being or lifestyle of an individual, family, community or institution due to some action.

Societal Cost Test - An evaluation of the costs and/or benefits accruing to society as a whole, due to an activity.

Societal Impact - The total impact of an activity on the economy, the environment, and society as a whole.

Supply-Side Options - Expansion or replacement projects, such as pipeline or storage construction, upstream of the customer's meter.

Synergy - A productivity or efficiency improvement resulting from the combination of two or more compatible actions or operations to yield a benefit which is greater, or a cost which is lower, than would be the case were the actions to have been pursued independently.

Technical Potential - The total amount of energy that could be saved if all energy uses were served by the most efficient technology or design currently available, without consideration of cost effectiveness, market and institutional barriers or limitations on manufacturing capability. (See also **Achievable Potential**)

Throughput - The total volume of natural gas consumption or utility gas sales which occurs in a specified time frame, usually measured annually.

Total (Financial) Costs - The sum of a utility's fixed and variable costs, including capital, operating and interest costs.

Total Market - All the customers in a given market sector, or sub-sector targeted for a DSM program.

Total Resource Cost Test - An evaluation which incorporates all of the costs and benefits included in the Societal Cost Test with the exception of externalities.

Trade Allies - Organizations that cooperate in the provision of goods and/or services and, in doing so, affect the energy-related decisions of customers who might participate in DSM programs.

User-Pay - The principle which requires beneficiaries of a program, service or facility to pay their proportionate share of the total cost of the program, service or facility.

Utility Costs - Costs incurred by a utility in a given year for the operation of a DSM program or portfolio. Includes administration costs.

Utility Incentive - A regulatory measure which rewards a utility when it achieves a specified target. Also referred to as a shareholder incentive.

Utility Test - An evaluation of the impact of a DSM program on a utility's revenue requirement as a result of changes in costs. Excludes any lost revenues due to the DSM program.

Value of Service Rates - Rates which are not strictly based on cost causality, but also considers other factors such as the customer's ability to use an alternative to natural gas.

Variable Costs - Costs that vary proportionally with throughput. (Also see **Fixed Costs**)

APPENDIX C

THE BOARD'S E.B.O. 134 FINDINGS ON ECONOMIC FEASIBILITY TESTS

The Board finds that of the tests currently in use by the utilities, the DCF analysis provides a superior measure of the subsidy required from existing customers for a particular project.

The Board directs all utilities to employ DCF analysis as part of its assessment of the feasibility of projects for system expansion.

The Board encourages the use of more formal risk measurement in the feasibility test and it would not discourage the use of sensitivity analyses of variables being regularly employed in the test.

The Board finds that incremental costs should be used in evaluating the feasibility of system expansion.

The Board will continue to assess the adequacy of the DCF analysis and any other tests used for project evaluation at the time of a utility's rate case hearing.

The Board finds that Union's three-stage test has considerable merit. The Board requires each utility to develop a three-stage process as outlined below to aid the Board in its determination of the public interest.

The first stage is a test based on a DCF analysis.

The second stage should be designed to quantify other public interest factors not considered at stage one. All quantifiable other public interest information as to costs and benefits should be provided at this stage.

The third stage should take into account all other relevant public interest factors plus the results from stage one and stage two.

A project could, therefore, be accepted if it passed the DCF analysis of stage one and if the disadvantages and quantifiable costs from stages two and three do not disqualify it. If a project is not acceptable because it fails the DCF analysis or has significant other disadvantages, then stages two and three must be completed before the project can be said to be fully evaluated.

The Board is aware that each utility will continue to approve internally projects that lie within areas for which a franchise and a certificate of public convenience and necessity have been issued. At subsequent rate hearings the Board may assess the analyses employed before approving the inclusion in rate base of any specific project.

Any project brought before the Board for approval should be supported by all data used by the Applicant in reaching its conclusion that the project is viable. The utilities and other interested parties may use alternative analyses, but these and the results must be presented at the relevant hearing. The Board will continue to weigh the various benefits against the various disadvantages as it always has in reaching its decision in the public interest.

The Board continues to hold the opinion that it is appropriate for existing customers to subsidize, through higher rats, financially non-sustaining extensions that are in the overall public interest if the subsidy does not cause an undue burden on any individual, group or class.

Exhibit L.EGD.GEC.2

Before the Ontario Energy Board

EB-2013-0451

DSM Potential in the GTA

Prepared by:

Chris Neme & Jim Grevatt
Energy Futures Group

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

June 28, 2012

I. INTRODUCTION

Enbridge Gas has proposed a complex and expensive new pipeline project to serve the Greater Toronto Area (GTA). A very brief part of the Company's filing addresses its consideration of alternatives to the proposed project,[1] including energy efficiency delivered through the utility's Demand Side Management (DSM) programs. This report critiques the Company's assessment of DSM as an alternative and puts forward an estimate of how much additional peak hour savings could be achieved in the geographic area of interest if Enbridge were to ramp up its DSM investments. In particular, we focus on the geographic area that is purported to be driving the need for Segments B1 and B2 of the pipeline.[2]

The development of this evidence was coordinated with the development of evidence filed on behalf of Environmental Defence by Ian Jarvis of EnerLife. Among other things, our evidence assesses how much additional efficiency savings is achievable in aggregate (i.e. a "top-down approach" looking across all sectors) based on the experience of leading jurisdictions. It also looks a little more closely at the savings potential in the residential sector. We do not perform a comparable "deeper dive" into savings potential in the commercial and/or apartment sectors because we understood that Mr. Jarvis would be doing so.

The development of our evidence was also coordinated with the development of evidence filed on behalf of the Green Energy Coalition (GEC) by Paul Chernick of Resource Insight. Our estimate of the magnitude of additional peak hour savings that Enbridge could realize from DSM was provided to Mr. Chernick to incorporate in his evidence on the mix of alternatives that could defer the need for the pipeline project to meet load growth.

Mr. Neme, one of the co-authors of this report, has more than 20 years experience with the design, implementation and evaluation of energy efficiency programs and policies. He previously filed testimony on DSM/CDM issues before the Ontario Energy Board on numerous occasions over the past two decades (EBRO 487, EBRO 493/494, EBRO 497, EBRO 499, RP-1999-0001, RP-1999-0017, RP-2001-0029, RP-2001-0032, RP-2002-0133, RP-2003-0063, RP-2003-0203, EB-2005-0211, EB-2005-0001, EB-2005-0523, EB-2006-0021, EB-2008-0346, EB-2010-0279; EB-2012-0337), as well as before similar regulatory bodies in Quebec, Connecticut, Illinois, Maine, Maryland, Michigan, New Jersey, Ohio and Vermont. Mr. Neme is also intimately familiar with Enbridge's current and past DSM efforts from serving on the current Ontario Technical Evaluation Committee (TEC), serving on all but one of Enbridge's annual DSM Audit Committees since they were first formed in 2000 (including the current audit committee charged with

[1] Exh. A, Tab 3, Schedule 7
[2] This should not be construed to imply an endorsement of any other segment of the pipeline project. We take no position on the relative merits of the other segments. Our testimony is simply focused on the portions of the pipeline project which GEC witness Chernick has identified as potentially deferrable through greater investment in demand-side resources.

reviewing the Company's 2012 DSM savings), and having played a lead role in negotiating the settlement agreement between Enbridge Gas and stakeholder groups on Enbridge's 2012-2014 DSM plan.[3] In addition to his work in Ontario for the GEC and OPA, Mr. Neme has consulted on DSM issues for clients in more than 20 different states, several Canadian provinces and several countries in Europe. That includes extensive experience with the integration of DSM into system planning which culminated last year in the publication of a report on North American experience with the use of energy efficiency to defer electric transmission and/or distribution system investments.[4]

Mr. Grevatt, the other co-author of this report, also has more than 20 years experience with the design, implementation and evaluation of efficiency programs. Prior to joining Energy Futures Group, Mr. Grevatt worked for the Vermont Energy Investment Corporation – both as a senior consultant to clients out of state (two years) and as the manager of Efficiency Vermont's statewide residential efficiency programs (five years). Mr. Grevatt also worked for Vermont Gas Systems (VGS) for 11 years, the last five of which he was responsible for managing all of VGS' DSM efforts (residential, commercial and industrial). Mr. Grevatt has filed regulatory testimony on gas and electric DSM issues in both Vermont and Illinois.

Curricula Vitae for both Mr Neme and Mr Grevatt are found at Exhibit L.EGD.GEC.4.

II. Enbridge's Consideration of DSM as a Potential Alternative to the GTA Pipeline

1. The Extent of Enbridge's Assessment of DSM

Enbridge has, by its own admission, done essentially no analysis of the role that more aggressive DSM could play in deferring or eliminating the need for any part of its pipeline project. Indeed, the Company's discussion of DSM as an alternative in its filing is less than 1½ pages long, and most of that discussion is focused on the fact that a very small minority of the efficiency measures that it currently promotes through its programs could exacerbate peak demands.[5] As discussed below, subsequent discovery makes clear that such measures are not representative of most DSM. When pressed on the question of what Enbridge did to assess the role DSM could play in deferring any part of the pipeline project, the Company's witnesses made clear that its quantitative assessment of DSM was limited to an extremely high level and very rough quantification of the level of savings that would be needed to fully address *all* aspects of the *entire* pipeline project:

[3] Mr. Neme was elected by the broader stakeholder Collaborative to serve on the audit committees and the TEC.
[4] Neme, Chris and Richard Sedano, *"U.S. Experience with Efficiency as a Transmission and Distribution System Resource"*, published by the Regulatory Assistance Project, February 2012.
[5] Exh. A, Tab 3, Schedule 7, pp. 1-3.

> "when we looked at DSM we looked at the rough order of magnitude (of) what we thought would potentially be achievable in terms of peak demand reduction…(and) When we talk about 600 terajoules a day, we felt that was so far away from anything that we could possibly hope to achieve that we screened that out as an alternative…Our level of detail is not any more than that."[6]

In short, the Company simply asked itself whether all of the "needs" driving all of the elements of a complex multi-component project could be deferred by DSM. The Company did not adequately assess whether different individual elements of the project could be cost-effectively deferred.

2. Enbridge's Planning Failure

That all-or-nothing approach to planning is highly problematic. For example, the 1600 terajoules (TJ) referenced above relates to the amount of gas that would be supplied from different sources, as a result of construction of new facilities around Parkway and Segment A of the GTA project. As GEC's witness Mr. Chernick explains, even if the shift in sourcing of gas justified some portions of the GTA project, that objective would not justify Segment B. The Company has also argued that it needs 160 TJ per day reduction to reduce the pressure in the existing Don Valley line to 30% SMYS. However, as Mr. Chernick also explains, the Company has operated the Don Valley line at pressures above 30% SMYS since 1971,[7] so it is unclear pressure reductions should now be sufficient justification for such an expensive capital investment. Thus, as Mr. Chernick explains, the only *potentially* compelling rationale for Segment B is that forecast load growth will create reliability problems if the segment is not built.

Enbridge has forecast that load growth in the GTA influence area is approximately 18 TJ per peak day (after accounting for the effects of currently planned DSM)[8] – far less than 600 TJ or 160 TJ. The Company did not assess whether DSM, alone or in combination with other strategies, could more cost-effectively address such growth.[9]

That represents a fundamental failure in Enbridge's planning. A number of different jurisdictions are now actively assessing whether system reliability needs can be met through geographically targeted DSM. Put another way, they are conducting integrated resource planning any time a significant system reliability concern that is related to load growth reaches the point where a future response is forecast to be needed. Capital investments on the supply-side are then compared to alternative investments on the demand-side.[10] These same principles should apply equally to electric and gas systems. Again, they have clearly not been followed by Enbridge in this case.

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[6] June 13th Technical Conference transcript, p. 121, lines 2-9.
[7] June 12th Technical Conference transcript, p. 32, lines 1-3.
[8] June 13th Technical Conference transcript, p. 103, lines 9-10.
[9] Note that though we cite Enbridge's estimates of peak load growth, we are not endorsing them. The Company's approach to the development of its forecast raises some questions. However, we have not assessed their forecast in sufficient detail to pass judgment on its reasonableness.
[10] Combinations of demand and (smaller) supply-side investments are also considered.

3. Enbridge's Failure to Fully Value DSM Peak Benefits

It is bad enough that the Company has not really considered the role that more aggressive DSM could play in deferring any part of the pipeline project as part of its recent application to the Board. What's worse is that the Company has known of a potential need for additional pipeline capacity (or equivalent) for a decade or more[11] and never adapted its DSM plans – by proposing larger levels of investment and savings, by geographically targeting more of its investment and/or by focusing more of its investment on saving of loads that drive peak demand – to address the potential need.

Unlike some other gas utilities, the Company has never even quantified the peak hour or peak day benefits of its efficiency programs. Nor has it assigned economic value to peak day or peak hour savings. The avoided costs that Enbridge has used to conduct cost-effectiveness screening of its DSM measures and programs are expressed entirely in dollars per *annual* m^3 of gas energy saved. Moreover, those avoided costs appear to be comprised entirely of avoided commodity costs, avoided transportation charges and avoided storage.[12] There does not appear to have been any value assigned to deferring capital investments in pipelines that would otherwise be needed to address peak capacity constraints. The Company summed this up clearly in the Technical Conference:

> *"…we do everything within the DSM program on the basis of* ***annual*** *savings".*[13] (emphasis added)

This suggests that the Company has never really considered DSM as a potential peak capacity resource. As a result, they have probably understated the benefits of their historic DSM efforts and, more importantly, failed to adapt their DSM efforts to maximize benefits to rate-payers.

4. DSM's Role in Reducing Peak Demand

As noted above, most of the extremely brief discussion of DSM as an alternative in the Company's initial filing was focused on the point that some efficiency measures – such as setback thermostats and tankless water heaters – can exacerbate peak demands by shifting loads from off-peak hours to on-peak hours. However, that argument is, at best, a distraction. The amount of attention devoted to it in Enbridge's filing (relative to discussion of the peak benefits of the overwhelming majority of efficiency measures) is completely inappropriate.

When asked during the Technical Conference to identify which specific efficiency measures that the Company promoted in 2012 could exacerbate peak demands, the Company identified only one that would definitely have that effect (residential

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[11] During the June 13th Technical Conference Enbridge stated that the capacity shortfall at Station B as foreseen at least as early as 2002 (Transcript p. 116, lines 19-26).
[12] EB-2012-0384, Exh. B, Tab 2, Schedule 2.
[13] June 13th Technical Conference Transcript, p. 129, lines 6-8.

programmable thermostats) and three others that might (commercial programmable thermostats, demand control ventilation that is occupancy based and other commercial "controls"). The Company stated that the other 54 measures it promotes would decrease both annual *and* peak loads.[14]

It is also worth noting that the one measure the Company identified in its Technical Conference undertaking response as definitely adding to peak loads, residential programmable thermostats, accounts for a negligible portion – on the order of 0.1% or less – of the Company's DSM savings.[15] Given available data, it is difficult to estimate exactly how much of the Company's DSM savings which are associated with the other measures that the Company identified as *possibly* adversely affecting peak (e.g. controls installed at commercial buildings or industrial facilities) would actually adversely affect peak loads. In aggregate, commercial and industrial controls appear to account for about 10-15% of the Company's total savings in 2010 and 2011.[16] However, a significant portion of those savings are likely to actually disproportionately *save* energy at the time of peak rather than exacerbate peak loads.[17]

Put simply, the vast majority of the Company's DSM savings are being produced by measures that save energy at peak hours. The same would be true of almost any imaginable expansion of the Company's DSM efforts – particularly if the expansion was specifically designed to defer pipeline investments.

III. Opportunities for Increasing DSM Savings in the GTA

1. Characteristics of GTA Loads

Table 1 summarizes the gas load forecast in the GTA for 2013. Several important points should be gleaned from these data. First, the industrial sector is responsible for a much smaller fraction of peak hour loads than of total annual energy usage. Indeed, the ratios of peak hour loads to annual consumption for the residential, apartment and commercial

[14] Exh. JT2.24
[15] It is not clear that the company acquired any energy savings in 2012 from residential programmable thermostats as they are not mentioned in its draft annual report, any of its related verification reports or the TRC spreadsheet in which it adds up all the savings achieved by measure. In 2011, all programmable thermostats, residential and non-residential (data on just the residential portion are not readily available), accounted for less than 30,000 annual m^3 savings out of a DSM portfolio total of more than 77 million m^3 (Exh. I.A4.EGD.GEC.35, Attachment p. 4). In 2010, residential thermostats accounted for roughly 60,000 annual m^3 savings out of a DSM portfolio total of more than 65 million m^3 (Enbridge Gas Distribution, Inc., *2010 Draft DSM Annual Report*, April 14, 2011.)
[16] Exh. I.A4.EGD.GEC.35, Attachment p. 4, and Enbridge Gas Distribution, Inc., *2010 Draft DSM Annual Report*, April 14, 2011, Appendix A, Table 32.
[17] Consider, for example, occupancy linked demand control ventilation. The amount of ventilation provided by such systems in office buildings and even retail stores will decline quickly after 5 pm (i.e. as evening peak hours approach) with declining occupancy levels and not reach significant levels until 9 or 10 am the following morning (as occupancy increases – after the peak hour). Thus, in buildings for which the baseline condition was ventilation that was continuously running, inconsistently turned off and on, and/or turned off later at night and/or turned on early in the morning by custodial staff or others, substantial savings will occur on peak.

sectors are roughly three to three and a half times greater than for the industrial sector. This should not be surprising as industrial loads tend to be much less climate driven than non-industrial loads. However, it underscores that DSM efforts designed to address pipeline capacity concerns should focus on residential, apartment and commercial sectors. Second, the residential sector accounts for both 40% of annual energy sales and 40% of peak hour demands. This is important because, as discussed further below, only a very small fraction of the Company's current DSM savings are forecast to come from the residential sector.

Table 1: 2013 GTA Sales and Contributions to Peak Demands by Sector[18]

Sector	No. of Customers	Annual Gas Use 1000s m3	Annual Gas Use %	Peak Hour Load m3	Peak Hour Load %	Ratio of Peak m3 to Annual m3
Apartment	4,729	914,000	13%	428,717	15%	0.00047
Commercial	80,563	2,063,000	30%	1,119,742	38%	0.00054
Industrial	4,823	1,202,000	17%	184,791	6%	0.00015
Residential	904,728	2,730,000	40%	1,178,633	40%	0.00043
Total		6,909,000		2,911,883		0.00042

2. Enbridge's Currently Planned DSM for the GTA

Table 2 summarizes the impacts of Enbridge's currently planned DSM programs on the GTA portfolio. A couple of points are worth highlighting. First, as noted above, Enbridge is forecasting that it will get almost none of its savings from the residential sector (just 2%) in 2013, even though that sector accounts for both the largest portion of annual sales (40%) and the largest contribution to peak hour loads (also 40%) in the region. Also, Enbridge is forecasting that it will achieve nearly 30% of its savings from the industrial sector even though that sector accounts for just 17% of annual sales and just 6% of peak hour loads. These results are not surprising. Enbridge's DSM portfolio is optimized so as to maximize total lifetime savings per dollar of spending. Under a framework in which total savings are all that matters, such an approach might make sense. However, consideration of the benefits of deferring large capital projects like pipeline expansions suggests a different approach would be appropriate (at least for the geographically targeted area that would otherwise be served by the pipeline investment). Finally, it is worth noting that Enbridge appears to be forecasting that it will achieve annual savings of about 0.5% of sales in the GTA. That is both lower than what it is forecasting to achieve in its entire service territory (0.65%)[19] and, as discussed further below, much less than what leading North American gas utilities are achieving.

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[18] Number of customers and annual gas consumption are from Exh JT2.36. Peak hour loads are from Exh. I.A4.EGD.ED.3.

[19] Exh. I.A4.EGD.GEC.34, p. 4 of 5.

Table 2: Impacts of Enbridge's Current DSM Programs on the GTA (2013)[20]

	Annual Savings			Peak Hour Savings	
Sector	**1000s m3**	**%**	**% of Sales**	**m3**	**% of Peak**
Apartment	8,638	24%	0.95%	4,052	0.95%
Commercial	15,400	43%	0.75%	8,359	0.75%
Industrial	10,876	30%	0.90%	1,672	0.90%
Residential	775	2%	0.03%	335	0.03%
Total	35,689		0.52%	14,417	0.50%

3. Potential for Additional DSM Savings in the GTA

One of the best indicators of how much additional savings could be acquired is the amount of savings other jurisdictions – particularly leading jurisdictions – are acquiring. There are numerous examples of Natural Gas utilities in North America that are achieving significantly greater savings through their DSM programs than Enbridge has demonstrated to date:

- Interstate Power and Light in Iowa achieved system wide annual savings of 1.50% of sales in 2009, with subsequent years at 1.29% and 1.42%. The average of these three years is over 300% of the savings that Enbridge achieved for the same period in the GTA.
- National Grid in Massachusetts increased annual savings from 0.54% of sales in 2010 to 1.29% in 2012, a 140% increase in three years starting at a level in 2010 that was already 23% more than what Enbridge achieved in the GTA in the same year.
- Questar Gas in Utah also demonstrated an impressively rapid ramp-up in their overall energy efficiency portfolio. Over a three-year span from 2007 to 2009 Questar increased portfolio-wide annual savings five-fold to nearly 1% of sales, more than double the level of savings that Enbridge is currently getting in the GTA.
- Vermont Gas Systems has averaged 1.0% annual savings over the past six years despite having few industrial customers within its service territory.'
- Xcel in Minnesota has similarly averaged approximately 1.0% annual savings over the past six years.

These examples and others clearly demonstrate that Enbridge could be capturing much greater savings through aggressive energy efficiency than it has been capturing to date. Moreover, these savings are occurring in the absence of imminent "necessary" capital expenditures such as those that Enbridge has put before the OEB. Despite Enbridge's

[20] Annual savings in the GTA are from Exh. I.A4.EGD.GEC.34, p. 4 of 5. Savings as % of sales calculated using sales values shown in Table 1 (from Exh. JT2.36). Peak hour savings calculated using ratios of peak hour loads to annual sales in Table 1 (derived in part from Exh. I.A4.EGD.ED.3).

failure to examine construction alternatives for over a decade, it is still not unreasonable to think that, approached with the real urgency at hand, Enbridge could drive greater near term results even than those currently being attained by industry leaders elsewhere, and that these results could mitigate at least a significant part of the need for the proposed Segment B.

In summary, as demonstrated in Table 3 below, leading natural gas efficiency programs have been able to demonstrate rapid ramp up and are achieving portfolio-wide annual savings on the order of 1.0% to 1.5% of annual sales, or more than two to three times the recent historical experience of only about 0.47% per year for Enbridge within the GTA.[21]

Table 3: Gas Savings as % of Sales – Enbridge vs. North American Leaders[22,23]

	Enbridge		Leading Jurisdictions				
Year	System-Wide	GTA	Questar (UT)	Interstate Power & Light (IA)	Vermont Gas Systems (VT)	Xcel (MN)	National Grid (MA)
2007	0.76%	0.55%	0.19%	n.a.	0.89%	1.12%	n.a.
2008	0.67%	0.49%	0.38%	0.71%	1.14%	0.80%	n.a.
2009	0.62%	0.45%	0.98%	1.50%	0.73%	0.87%	0.68%
2010	0.60%	0.44%	n.a.	1.29%	0.97%	0.99%	0.54%
2011	0.67%	0.49%	n.a.	1.42%	1.30%	n.a.	0.85%
2012	0.55%	0.43%	n.a.	n.a.	0.91%	1.09%	1.29%

[21] Enbridge's forecast GTA savings as a percent of sales for 2013 and 2014 are slightly higher than recent years (0.52% for both years), but still well below levels being achieved by North American leaders.
[22] Note that this is not necessarily a definitive list of leading gas DSM jurisdictions. We have not conducted the kind of comprehensive assessment necessary to identify all of the leading jurisdictions.
[23] Enbridge system-wide savings as % of sales and GTA savings from Exh.I.A4.EGD.GEC.34; GTA sales are from JT2.36. Questar savings data for 2007 – 2009 from Dan Dent, Questar program manager, "Regional Round Up: Southwest Region and Questar Gas," CEE, March 18, 2010. Questar sales data for 2007-2009 were obtained from annual 10-K filings. IPL savings and sales data were obtained from regulatory filings including annual reports filed with the Iowa Utilities Board. Vermont Gas Systems savings data were obtained from the VGS annual demand-side management reports, while sales data were obtained from the U.S. Energy Information Administration. Xcel Energy data were obtained from regulatory filings including CIP Status Reports and 2010-12 and 2013-15 Plans. National Grid savings data for Massachusetts were obtained from energy efficiency annual reports for 2009-2011 and from the fourth quarter Program Administrators quarterly report filed with the Massachusetts Energy Efficiency Advisory Council for 2012. Sales data were reported by the Program Administrators, including National Grid, during the most recent (2013-2015) Massachusetts energy efficiency planning process.

4. Achievable Residential Sector Savings

As discussed above, one of the reasons Enbridge's DSM savings levels are below those of leading gas DSM jurisdictions is that it is acquiring very little savings from the residential sector. There is an enormous untapped potential from retrofitting residential buildings.

There is no shortage of examples of effective, high-achieving efforts to capture such savings in other jurisdictions. In some cases, significant year after year savings have been achieved for more than a decade. In other cases, there has been a quick ramp up of participation and savings in recent years. Selected examples worth noting are as follows:

- The Canadian EcoENERGY program (with considerable complementary support from the province of Ontario) built a considerable business infrastructure for home retrofit services. In Ontario, the program ramped up from about 9500 completed home retrofits in the 2007-2008 year – about 0.25% of the eligible housing stock – to nearly 170,000 – about 4.4% of the eligible housing stock – in the 2010-2011 year.[24] To be sure, not all of those participants did whole house retrofits. Many simply installed a single measure, often just a new furnace.[25] However, roughly half of the measures installed were thermal envelope measures, including insulation upgrades, window and door replacements and draft sealing.[26]
- In the United Kingdom, the six major energy suppliers (competitive retailers supplying both electricity and gas) installed attic insulation in nearly 1.4 million homes over the two-year period ending March 2010 – about 3.5% of all single family homes in the country each year. They also installed wall insulation in 1.1 million homes (equivalent to roughly 2.8% of all single family homes per year) over the same time period.[27]
- Questar, referenced above for its rapid ramp-up of savings at the portfolio level reported that it provided natural gas service to 823,151 residential customers in 2008, roughly comparable to the 849,520 residential customers in the GTA in 2008 as reported by Enbridge.[28] In 2010, 65% of Questar's roughly 27 million m^3 annual DSM savings came from residential retrofits, clearly demonstrating that the potential for achieving high levels of savings is not limited to the commercial sector.

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[24] EcoENERGY program Status Report June 2013 data, by province, provided in a spreadsheet by Office of Energy Efficiency, Natural Resources Canada

[25] From April 2007 to March 2010, 23.5% of Ontario participants installed just a single measure and nearly three quarters of those single measure participants installed new furnaces (Environmental Commissioner of Ontario, *Re-thinking Energy Conservation in Ontario – Result: Annual Energy Conservation Progress Report – 2009 (Volume 2)*, November 2010.

[26] Ibid.

[27] Neme, Chris, Meg Gottstein and Blair Hamilton, *Residential Efficiency Retrofits: A Roadmap for the Future*, published by the Regulatory Assistance Project, May 2011.

[28] Exh. I.A4.EGD.ED.4.

- As documented in the recently released *Leaders of the Pack: ACEEE's Third National Review of Exemplary Energy Efficiency Programs*[29], the Mass Save® Home Energy Services (HES) Program in Massachusetts is cost-effectively providing comprehensive services to thousands of residential customers annually. Nearly 11,000 Massachusetts customers received retrofits in 2012. That number does not include thousands of additional low income retrofits completed in the state. It has been estimated that the combined participation of both low income and non-low income retrofit programs in Massachusetts in 2009 represented approximately 1.25% of the single family housing stock in the state.[30]
- After an initial start-up/set-up of several months, Efficiency Maine's Home Energy Savings Program began completing whole house retrofits at a rate of nearly 3000 per year – or an annual market penetration rate of 0.6% of the eligible housing stock in the first year.[31] The program was also very successful in the following year until it ran out of money (it was funded with federal dollars). The average savings per participant was 31% of total baseline energy use.[32]
- It has been estimated that in the combined participation of both low income and non-low income retrofit programs in Vermont in 2009 represented approximately 1.2% of the single family housing stock in the state.[33]

In summary, experience from leading jurisdictions suggest it is possible to achieved market penetrations of residential thermal envelop retrofits of 1% to 2% per year – an order of magnitude more than Enbridge's planned market penetration rate of roughly 0.1% for its combined efforts to retrofit both low income and non low income homes in 2013.[34] Experience in leading jurisdictions also suggests that savings on the order of 20-35% per treated home are eminently achievable. Table 4 shows how much residential savings could be achieved in the GTA if Enbridge were to launch a much more aggressive effort to promote whole house retrofits.

[29] Nowak, Seth, et al. *Leaders of the Pack: ACEEE's Third National Review of Exemplary Energy Efficiency Programs*, published by the American Council for an Energy Efficient Economy, June 2013.
[30] Neme, Chris, Meg Gottstein and Blair Hamilton, *Residential Efficiency Retrofits: A Roadmap for the Future*, published by the Regulatory Assistance Project, May 2011.
[31] Based on participation data from Efficiency Maine, Draft HESP Final Report, December 21, 2012.
[32] The Cadmus Group, *Efficiency Maine Trust Home Energy Savings Program Final Evaluation Report*, November 30, 2011.
[33] Neme, Chris, Meg Gottstein and Blair Hamilton, *Residential Efficiency Retrofits: A Roadmap for the Future*, published by the Regulatory Assistance Project, May 2011.
[34] Enbridge has adopted a goal of retrofitting approximately 1700 single family homes in 2013 – 732 non-low income homes and approximately 1000 low income homes (EB-2012-0394, Exh. B, Tab 2, Schedule 9, pp. 12 and 16) out of a total 1.84 million Rate 1 customers (EB-2013-0046, Exh. B, Tab 3, Schedule 4).

Table 4: Achievable Residential Savings Potential in the GTA[35]

	Market Penetrations		Homes Treated		Annual m3 Savings				Peak Hour m3 Savings	
					Incremental Annual		Cumulative Annual			
Year	Incremental Annual	Cumulative	Incremental Annual	Cumulative	(1000s m3)	% of Res. Sales	(1000s m3)	% of Res. Sales	Incremental Annual	Cumulative
2014	0.50%	0.50%	4,524	4,524	5,397	0.20%	5,397	0.20%	2,330	2,330
2015	1.00%	1.50%	9,047	13,571	10,794	0.39%	16,191	0.58%	4,660	6,990
2016	1.50%	3.00%	13,571	27,142	16,191	0.58%	32,382	1.15%	6,990	13,980
2017	1.50%	4.50%	13,571	40,713	16,191	0.57%	48,573	1.71%	6,990	20,971
2018	1.50%	6.00%	13,571	54,284	16,191	0.56%	64,764	2.25%	6,990	27,961
2019	1.50%	7.50%	13,571	67,855	16,191	0.56%	80,955	2.78%	6,990	34,951
2020	1.50%	9.00%	13,571	81,426	16,191	0.55%	97,146	3.30%	6,990	41,941
2021	1.50%	10.50%	13,571	94,996	16,191	0.54%	113,337	3.81%	6,990	48,932
2022	1.50%	12.00%	13,571	108,567	16,191	0.54%	129,528	4.30%	6,990	55,922
2023	1.50%	13.50%	13,571	122,138	16,191	0.53%	145,719	4.78%	6,990	62,912
2024	1.50%	15.00%	13,571	135,709	16,191	0.53%	161,910	5.25%	6,990	69,902

Note that the home retrofit ramp up assumed in Table 4 leads to incremental savings as a percent of sales of about 0.55% from 2016 through 2024 and cumulative savings as a percent of sales of 5.25% over the 2014-2024 (i.e. 11 year) period.[36] For comparison purposes, in its 2008 Update of natural gas efficiency potential in the Enbridge service territory, Marbek projected that after 10 years Enbridge could cost-effectively save 5.0% of its residential load under a $20 million annual DSM budget scenario, 5.7% under a $40 million annual DSM budget scenario and 7.5% under a scenario in which budgets were constrained only by whether the savings targeted were cost-effective.[37]

5. Total Achievable Residential Sector Savings

As noted above, Enbridge should be able to ramp up – over several years – to the point where it is achieving annual energy savings in the GTA of 1.0% to 1.5% per year – roughly doubling to tripling its recent levels of DSM savings in the region. A significant portion of that increase should come from a substantial effort to promote residential whole house retrofits. Table 5 provides an estimate of how those savings might be achieved, by sector, as well as what the resulting peak hour savings would be.

As noted in Table 2 above, we estimate that Enbridge's current DSM programs will produce approximately 14,000 peak hour m^3 savings in 2013; absent any change in the Company's DSM efforts, similar incremental annual peak hour savings would be

[35] The number of homes treated is a function of forecast market penetration rates and a stock of existing 2013 residential customers of 904,728 (Exh. I.A4.EGD.ED.4). Annual savings per home is based on an assumed 30% savings per home multiplied by estimated baseline annual usage of 3977 for the 30% highest consuming homes which would be the most likely target market for a program (derived from Exh. JT2.36 and Exh. I.A1.EGD.GEC.16). Peak hour savings based on ratio for 2013 presented in Table 1. Savings as % of sales estimated using forecast residential sales from Exh. JT2.36.

[36] Note that it is likely possible to achieve additional savings from other measures targeted to the residential sector (e.g. more efficient appliances, more efficient heating and water heating equipment, more efficient new construction, etc.) which are not captured in our analysis.

[37] Exh. I.A4.EGD.ED 14, pp. 17 and 18 of Attachment.

achieved in 2014.[38] The ramp up that we are proposing would result in roughly 23,000 peak hour m^3 savings in 2014 (about a 9,000 peak hour m^3 – or 60% - increase over Enbridge's currently planned efforts), roughly 30,000 peak hour m^3 savings in 2015 (about a 15,000 peak hour m^3 increase, or about a doubling of Enbridge's current annual plans) and roughly 37,000 incremental annual peak hour m^3 savings per year thereafter (about a 23,000 peak hour m^3 increase, or roughly a 165% increase over Enbridge's current annual plans).

Table 5: Incremental Annual Achievable Savings Potential (All Sectors) in the GTA

	Annual Savings (000s m3)						Peak Hour Savings (m3)					
Year	Apart.	Com.	Ind.	Res.	Total	% of Sales	Apart.	Com.	Ind.	Res.	Total	% of Peak
2014	11,229	24,640	14,139	5,397	55,405	0.79%	5,267	13,374	2,174	2,330	23,145	0.79%
2015	14,253	29,260	17,945	10,794	72,252	1.03%	6,685	15,882	2,759	4,660	29,986	1.01%
2016	14,253	37,730	17,945	16,191	86,119	1.22%	6,685	20,479	2,759	6,990	36,913	1.24%
2017	14,253	37,730	17,945	16,191	86,119	1.20%	6,685	20,479	2,759	6,990	36,913	1.23%
2018	14,253	37,730	17,945	16,191	86,119	1.19%	6,685	20,479	2,759	6,990	36,913	1.22%
2019	14,253	37,730	17,945	16,191	86,119	1.18%	6,685	20,479	2,759	6,990	36,913	1.21%
2020	14,253	37,730	17,945	16,191	86,119	1.17%	6,685	20,479	2,759	6,990	36,913	1.20%
2021	14,253	37,730	17,945	16,191	86,119	1.16%	6,685	20,479	2,759	6,990	36,913	1.19%
2022	14,253	37,730	17,945	16,191	86,119	1.15%	6,685	20,479	2,759	6,990	36,913	1.18%
2023	14,253	37,730	17,945	16,191	86,119	1.14%	6,685	20,479	2,759	6,990	36,913	1.18%
2024	14,253	37,730	17,945	16,191	86,119	1.13%	6,685	20,479	2,759	6,990	36,913	1.17%

It should be emphasized that the two key conclusions presented in Table 5 are that it should be possible to ramp up to approximately 1.2% incremental annual energy savings[39] per year and that a significant portion of that ramp up should be associated with the residential sector. The allocation of savings by sector is illustrative only.[40] We use the term illustrative to underscore that we have not developed a detailed DSM plan, from the bottom up, to achieve these savings. Nor have we developed a new detailed efficiency potential study. Rather, we have taken a "top down" approach, extrapolating from other leading jurisdictions, some past experiences in Ontario and Enbridge's own experience. That approach is more than sufficient to demonstrate that there is sufficient additional achievable potential in the GTA (including the significant portion of GTA load that lies in the corridor served by the Don Valley NPS 30 line) to have warranted consideration by Enbridge in developing its pipeline project proposal.

[38] Exh. I.A4.EGD.GEC.34.

[39] Note that though baseline sales are projected by Enbridge to grow over time, we have held our absolute savings levels constant after a three year ramp up. As a result, savings as a percent of sales decline gradually to closer to 1.1% by 2024. This is a conservatism in our approach because the addition of new loads should offer the opportunity for additional savings.

[40] Our illustrative example assumes residential savings equal to those we estimated as possible from just an aggressive whole house retrofit program in the section above; industrial savings on the order of 1.5% of sales per year, consistent with the efficiency potential study conducted for Enbridge by Marbek (Exh. I.A4.EGD.ED 14, p. 57 of Attachment); apartment savings ramping up to between 1.4% and 1.5% of sales; and commercial savings ramping up to between 1.6% and 1.8% of sales.

It should also be emphasized that though we have not conducted a detailed assessment of the cost-effectiveness of such an expanded portfolio, there is every reason to believe that such an expansion would be cost-effective, adding significantly to the net benefits of Enbridge's current DSM efforts. We would expect that most, if not all of the savings achieved under an expanded portfolio to come from the same efficiency measures that Enbridge is currently promoting (including, as we understand Environmental Defence witness Jarvis will be suggesting, significant low cost savings from operational improvements to commercial and multi-family buildings which Enbridge's programs are only this year beginning to capture) – and Enbridge is currently estimating that its 2013 and 2014 DSM plans will produce approximately $4 in societal economic benefits (under the Total Resource Cost test) for every $1 in societal costs.[41]

The principal difference between the expanded portfolio and the Company's current portfolio is that the Company would need to achieve much greater market penetrations of the measures it is currently promoting. That could be accomplished by greater financial incentives to encourage more consumers to invest in the measures; by moving some incentive offerings upstream (i.e. to retailers, vendors, distributors, and possibly even manufacturers rather than just to consumers) which can achieve broader market penetrations, sometimes at lower program costs per unit of savings; and/or by increasing marketing efforts.

In general, that combination of strategies would lead to greater levels of DSM spending. However, it is important to note that higher levels of spending do not mean lower societal net benefits. If the efficiency measures themselves are cost-effective, and higher incentives lead to more of the measures being installed, then net benefits will increase.[42] Sometimes higher spending levels will produce not only greater absolute net benefits (the most important metric of DSM performance), but also greater benefit-cost ratios. This can occur both because greater customer participation means relatively fixed program and overhead costs can be spread across a greater depth of savings and because free ridership typically declines as incentive levels increase.

In response to an undertaking request, Enbridge suggested that the net economic (TRC) benefits of expanding its DSM portfolio to eliminate load growth in the GTA would be approximately $140 million per year – or nearly $1.7 billion over the 2014-2025 timeframe – if the cost-effectiveness of the expanded DSM effort was the same, per unit of savings, as the current DSM portfolio.[43] However, the Company also suggests that it would expect the expanded levels of DSM to be less cost-effective.[44]

In assessing the reasonableness of that conclusion, one must consider a variety of different factors. First, we would expect an increased relative reliance on some less cost-

[41] EB-2012-0394 Exh. B, Tab 2, Schedule 3.
[42] From the societal/TRC perspective, financial incentives are a transfer payment. Put another way, an efficiency measure costs what it costs. The only question is how much of the cost will be borne by the consumer and how much will be borne by the utility program.
[43] Exh. JT2.20.
[44] Ibid.

effective measures in Enbridge's current DSM portfolio – particularly residential retrofit measures – to cause some reduction in overall portfolio cost-effectiveness. However, some of the other factors noted above – e.g. increased focus on low cost operational efficiency improvements in non-residential buildings, spreading relatively fixed costs (including overhead and administration) over a larger volume of savings and reducing free ridership rates – would push in the opposite direction. Of course, as GEC witness Chernick shows in his evidence, deferral of pipeline investment would also add significant economic value. Without conducting a thorough planning exercise, it is difficult to say with any precision what the net result of these countervailing forces would be. However, given the cost-effectiveness of Enbridge's current DSM portfolio, we would be surprised if the net economic benefits of the significant DSM expansion we have suggested were not at least $0.5 billion – not including any additional benefits from deferring capital expenditures associated with the proposed pipeline project – over the next 12 years.

IV. Conclusions

To the extent that any portion of its pipeline project is driven principally by load growth, which GEC witness Chernick has indicated is the case for Segment B, Enbridge has clearly failed to adequately assess the role that expanded DSM could play as an alternative to its proposed pipeline investment.

Our analysis clearly demonstrates that Enbridge could significantly expand its current DSM efforts in the GTA region, generating substantial additional annual gas savings, substantial peak reductions – nearly offsetting all forecast load growth – and substantial economic benefits to Enbridge's customers even absent any impact on the Company's proposed pipeline project. We defer to GEC witness Chernick on the extent to which GTA-wide efficiency savings would, alone or in combination with other measures, provide additional economic benefits by deferring the need for elements of that project. To the extent that savings from just a portion of the GTA region are relevant to certain elements of the pipeline project, our GTA-wide savings estimates can be linearly scaled for any such smaller area of concern.

As discussed above, any significant expansion of DSM efforts in the GTA to defer pipeline project investment would require additional DSM spending (just as the pipeline project would). Enbridge's current DSM spending is in line with the Board's 2012-2014 DSM guidelines. However, it is should be noted that the Board's guidelines were established without consideration of the role that DSM could play in addressing some of the pending need for this extremely large capital investment by the Company. Also, to the extent that the guidelines were established in part to address concerns about cross-subsidies from non-DSM participants to DSM participants, it is worth noting that the economic benefit of any deferral of capital investments in new pipelines that would result from an expanded DSM effort would accrue to all customers, not just DSM participants. Of course, an expanded DSM effort would also mean that more customers would have the opportunity to become DSM participants. Further, it is worth noting that concerns about cross-subsidies apply at least as much to the pipeline investment as to DSM, as all customers would pay for the investment, not just the new customers that would be causing the increases in peak demand and, therefore, creating the need for the pipeline.

Enbridge Gas Pipeline Hearing EB-2012-0451

Evidence concerning Demand Side Management Potential in GTA

Ian Jarvis,

Wen Jie Li

Gillian Henderson

Enerlife Consulting

June 28, 2013, Updated September 11, 2013

Executive Summary

This report estimates the Demand Side Management ("DSM") potential for commercial and apartment customers in the GTA area, summarizes the DSM estimates for residential and industrial customers prepared by the consultants retained by the Green Energy Coalition ("GEC"), analyzes the potential DSM against load growth, estimates the present value of the commodity cost savings associated with the efficiency measures, and provides comments on Enbridge's load forecast model. The terms of reference provided to us by Environmental Defence appear at Appendix A to this report.

We conclude that all load growth in the GTA area can be completely offset through commercial and apartment DSM and that overall demand can be significantly *reduced* with the addition of residential and industrial DSM.

Enbridge estimates that its DSM programs will deliver in the order of 12 10^3 m^3 per hour (9 TJ/day) peak demand reduction savings each year. Enbridge also advises that additional peak demand reduction of 25 10^3 m^3/hr (18 TJ/day) is required each year to offset customer load growth. Therefore, a total of approximately 37 10^3 m^3/hr (27 TJ/ day) in peak demand reduction is required.

The forecast annual average peak demand reduction potential through DSM presented in this evidence yields a total of 50 10^3 m^3/hr (37.7 TJ/day) at the top quartile level, which is considered readily attainable in the timeframe involved. The average annual peak hourly reduction presented in the Enerlife model and by the GEC's witnesses is summarized as follows:

Table I. DSM Potential in the GTA Area	
Customer Sector	**DSM Potential (10^3 m^3/hr)**
Commercial (Per Enerlife Model, Top-Quartile Attainment)	31.0
Apartment (Per Enerlife Model, Top-Quartile Attainment)	11.3
Sub Total	**42.3**
Residential (Per Chris Neme)	5.6
Industrial (Per Marbek Report and Chris Neme's Analysis)	2.1
TOTAL	**50.1**

Median-quartile attainment would achieve 18.8 10^3 m^3/hr (14.2TJ/day) for commercial customers and 4.9 10^3 m^3/hr (3.7TJ/day) for apartment customers. The total present value of the avoided commodity costs at 2015 for attainment of the median performance target is $743 million and for the top quartile target is $1,108 million.

The Performance-Based Model presented in this evidence for calculating commercial and apartment DSM potential is derived from Enerlife's substantial and growing database of actual energy performance data for buildings. The approach is consistent with a growing number of provincial and national programs. [1] It takes a different approach from the DSM Potential Study conducted for Enbridge in 2009 by Marbek Resources Consulting Inc.[2] Rather than relying on technologies, assumed penetration levels and engineering calculations, the Performance-Based Model analyzes actual, benchmarked energy use of different building types and establishes the potential savings due to all buildings reaching intensity levels already achieved by one half (median) or one quarter (top-quartile) of the peer group.

Simply bringing high gas use intensity buildings down to meet median base and heating energy levels of existing buildings yields overall percentage savings in the order of 19% for commercial and 12% for apartment buildings. Going further to meet top-quartile performance levels raises the potential to over 32% for commercial buildings and almost 29% for apartments.

It should be noted that attainment of today's top quartile gas use is by no means the greatest savings level that can be planned for and expected within the timelines in question. By definition, one quarter of existing buildings are already performing at or better than this level. Energy efficiency initiatives such as REALpac's 20 by '15 Target and TRCA's Town Hall Challenge and Greening Health Care programs use top quartile gas use to set energy targets.

Measures to improve efficiency in high gas intensity buildings go beyond those included in Marbek's DSM Potential Study and are typically site-specific equipment repairs, upgraded control of buildings systems, and testing, tuning and rebalancing of heating plant and systems. Such projects show generally good Total Resource Cost ("TRC") test values, can be implemented quite quickly, and serve to improve building performance as well as energy efficiency. They require a systematic approach to identify target buildings, engage owners, isolate the inefficiencies, implement the necessary improvements and verify the results.

Enbridge is already starting down the path on this new, data-driven performance-based conservation programming with its Energy Compass and Run It Right programs. The company has also gained experience in this space through its sponsorship of and participation in Toronto & Region Conservation's programs and CivicAction's Race to Reduce. In order to deliver the substantial additional natural gas savings identified herein in an efficient and expedient manner, additional focus and expanded scope should be applied to these new programs. Working with other parties, Enbridge can readily identify and target the largest gas savings potential customers in each sector, and support them in understanding and achieving the considerable energy and cost savings potential in their buildings.

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[1] Examples include: Ministry of Education's Utility Consumption Database; REALpac's 20 by '15 Target and Benchmarking; Toronto & Region Conservation's Energy Efficiency Programs of The Living City; Government of Canada's Canadian launch of EPA's Portfolio Manager; CivicAction's Race to Reduce; Ontario Government's Green Energy Act reporting

[2] Exhibit I.A4.EGD.ED.14, Attachment

Part One - Natural Gas DSM Potential in the GTA – Enerlife Model

1.0 Performance-based DSM Forecast Methodology

Enerlife's model to forecast natural gas DSM potential in the GTA is based on established performance from a large multi-year database of energy use by buildings, direct project experience with successful high energy performing buildings and leadership of peer-reviewed initiatives aimed at determining conservation potential by defining how much energy individual buildings need. This differs from the DSM forecast model provided by Enbridge that points to a technology-centric view of DSM programs, rather than a performance-based one. This approach leads to a systematic approach to identifying buildings with savings potential and solution-based measures, often operational, that lead to quicker and greater gas savings.

Enerlife's Performance-based Forecast Model is supported by multi-year national pilot projects conducted by Enerlife on behalf of the Canada Green Building Council in the following building sectors: commercial office, government and utility administration, K-12 schools, retail bank branches, universities and municipal arenas. The pilots proceeded in parallel with and informed the technical development of the LEED standard for Existing Buildings: Operations & Maintenance.

These pilots were incredibly successful, and set the stage for the remarkable pace of market transformation which has taken place since they were completed. They brought awareness of opportunities to green existing buildings, engaged markets and generated interest in building performance. Enerlife's energy benchmarking and target-setting methodology introduced through the pilots has been adopted by the market, as evidenced by the REALpac 20 by '15 energy target, REALpac's Energy Benchmarking program, the reporting of energy intensity distribution of BOMA BESt certified buildings, Greening Greater Toronto's Race to Reduce awards, and others.

1.1 Data sets

For the commercial and apartment building sectors, we have assembled the largest full-year Canadian building data set in our online Green Building Performance System (GBPS) from the years 2009-2012. The GBPS employs IPMVP[3] methodology to weather-normalize gas consumption from different climatic regions to a common Toronto degree day base.

1.2 Building Sector Potential Savings

The graph below is illustrative of the benchmarking results for offices, schools, hospitals, retail, recreation and apartments respectively.[4] Each figure includes the size of the data set, indicates the range of base and heating gas use intensity (m3/ft2), and shows the overall percentage gas savings resulting from reaching median and top-quartile gas consumption levels.

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[3] International Performance Measurement and Verification Protocol

[4] The rest of the benchmarking results are in Appendix B

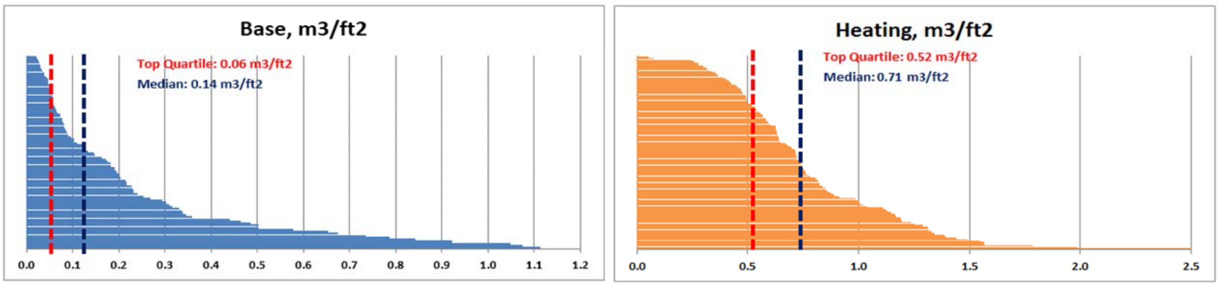
Figure 1 Example of Building Sector Benchmarking Results

Sector: Office Buildings

Number of buildings: 123
Total building area, ft2: 42,000,827

Gas usage	Savings potential, % at the attainment of	
	Median	Top Quartile
Base	47%	72%
Heating	23%	39%
Total	**27%**	**44%**

Based on 2010 data weather-normalized to Toronto. Data centres have been excluded.



Part Two – Load Forecast Model

The Performance-Based Model was prepared in order to more completely represent the effects of DSM on the peak hour demand forecast. The model applies the DSM savings projected in this report to the baseline (2011-2012) consumption, and then adds the full impact of new customer load growth (as projected by Enbridge) to the net usage. The model includes DSM projections for residential and industrial sectors based on the 2009 DSM report and the analysis completed by the GEC experts.

2.1 Annual DSM Savings Potential

The following table summarizes the total savings potential by sector, illustrating the difference if the median target is reached and the top quartile target.

Figure 2 Total Sector Savings Potential

Conservation Potential

Apartment			Commercial			Industrial			Residential		
Base	Heating	Total	Base	Heating	Total	Base	Heating	Total	Base	Heating	Total
Median Target											
12%	13%	13%	38%	16%	19%	15%	15%	15%*	5.25%	5.25%	5.25%**
Top Quartile Target											
23%	30%	29%	54%	28%	32%	15%	15%	15%*	5.25%	5.25%	5.25%**

**Marbek study of DSM potential indicates the economic potential is 919 million m^3 in the industrial sector by 2017 (i.e. within 10 years, given when they started their analysis). That is relative to a baseline of 2671, or a 34.4% savings. They estimate that they can get 43% of that amount in their financially unconstrained scenario and also in their $40 million annual budget scenario, for a total savings of 14.7%.*

*** Evidence provided in "DSM Potential in GTA" report by Chris Neme and Jim Gravatt is the basis for the residential savings potential by 2025.*

The present value of the avoided commodity costs for attaining the median performance target is $743 million and for the top quartile target is $1,108 million, using a 5.88% discount rate[5] and commodity costs used by Enbridge.[6]

Enbridge's current DSM programs capture 0.6% of their annual volume[7], while the Performance-based Model forecasts capturing 1.2% of the annual volume for the median target and up to 1.9% for the top quartile target as savings.

Commercial Sector breakdown

The following table summarizes the DSM Potential results for the five commercial building types presented in Part One to produce weighted average percent savings for commercial buildings as a whole.

Figure 3 Apartment and Commercial Sectors Savings Potential

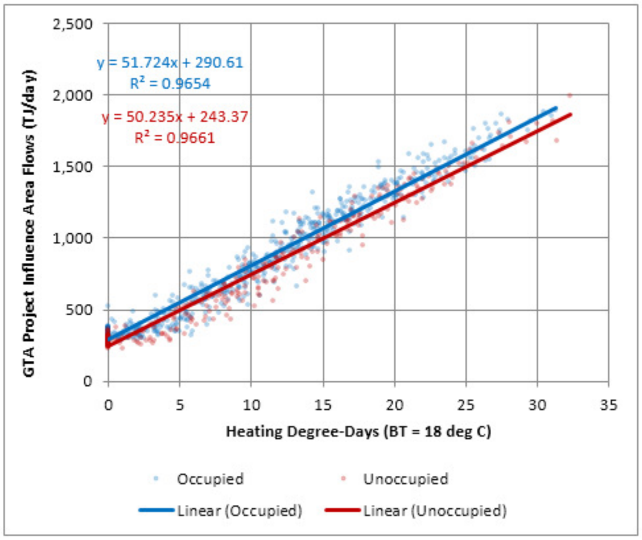
Database by Sector:	Buildings	Total building area, Mft2	Savings potential, % at the attainment of					
			Median			Top Quartile		
			Base	Heating	Total	Base	Heating	Total
Office	123	42.0	47%	23%	**27%**	72%	39%	**44%**
Schools	212	12.0	44%	17%	**21%**	63%	32%	**37%**
Hospitals	77	36.2	22%	12%	**18%**	52%	25%	**41%**
Retail	84	0.7	72%	26%	**37%**	87%	42%	**53%**
Recreation	20	1.4	56%	12%	**32%**	79%	29%	**52%**
Apartments	122	25	12%	13%	**13%**	23%	30%	**28%**

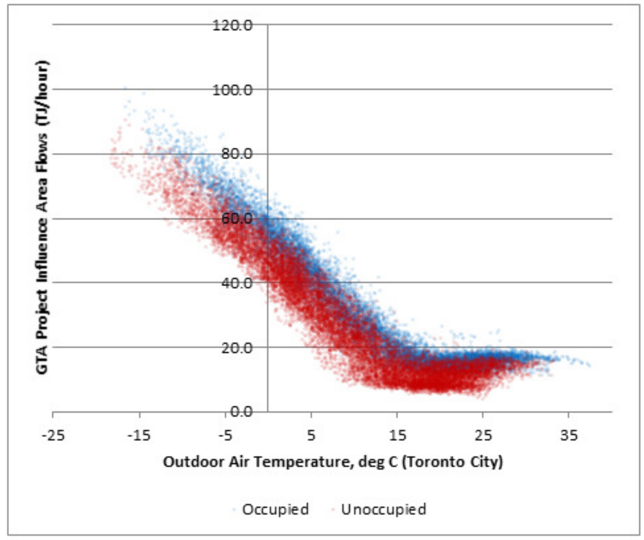
2.2 Peak Hourly Demand Savings

The Peak Breakdown worksheet of the model presents the hourly gas consumption data in 2010, 2011 and 2012 as provided by Enbridge for the GTA Project Influence Area (TJ/hour), relative to outdoor temperature. The analysis yields the breakdown of the base (16%) and heating (84% extrapolated to 41 HDD) on the Peak Breakdown worksheet. This is used to derive the impact of annual DSM savings on the system peak demand.

[5] The model uses the same discount rate as Enbridge uses for the Economic Feasibility. Exhibit E, Tab 1, Schedule1, Attachment, Page 1 of 5.
[6] Exhibit A, Tab 3, Schedule 5, Attachment Page 4 of 5.
[7] Calculated from current DSM estimate from Enbridge Exhibit I.A4.EGD.ED.25, Page 6 of 6.

Figure 4 Peak Hourly Demand





2.3 Peak Hourly Demand Forecast

The previous Peak Breakdown numbers inform the Peak Hourly Demand Forecast graphs below. Since this breakdown is not known for each sector, the same breakdown is used for Apartment, Commercial, Industrial and Residential. The base, heating and total DSM percentage potential for each of the four sectors originate from the Savings Model median and the top quartile scenarios. This also includes Enbridge's breakdown of the total peak demand (m3/hr) for each of the four sectors. Finally, the forecast percent attainment of the total potential is determined for each year from 2011 to 2025 to yield the peak demand reduction for each year.

This model incorporates the incremental gas demand over this period due to new customers coming on stream as projected by Enbridge.[8] However it should be pointed out that performance-based conservation plays an important role in setting design metrics and standards for new buildings, and that significant improvements can be expected over current design practice due to incorporating these into Enbridge's High Performance New Construction program. The potential impact on demand is unknown and was not included in the model.

The graphs below illustrate the variance between Enbridge's forecast of the impact of DSM on peak hourly demand and our performance-based forecast of the impact of DSM for the GTA Project Influence Area and individual building sectors. Included are:

- Baseline (2011-2012) which presents the actual historical peak demand data and simply projects 2011-2012 consumption through to 2025
- Baseline with Full Load Growth as provided by Enbridge

[8] Exhibit 1.A4.EGD.ED.2, Page 1 of 1

- Baseline with Discounted Load Growth which is Enbridge's forecast including the 35% reduction factor
- Baseline with Performance-based Forecast DSM (Median) and Full Load Growth
- Baseline with Performance-based Forecast DSM (Top Quartile) and Full Load Growth

Figure 5 GTA (all sectors) Peak Demand Forecast Model

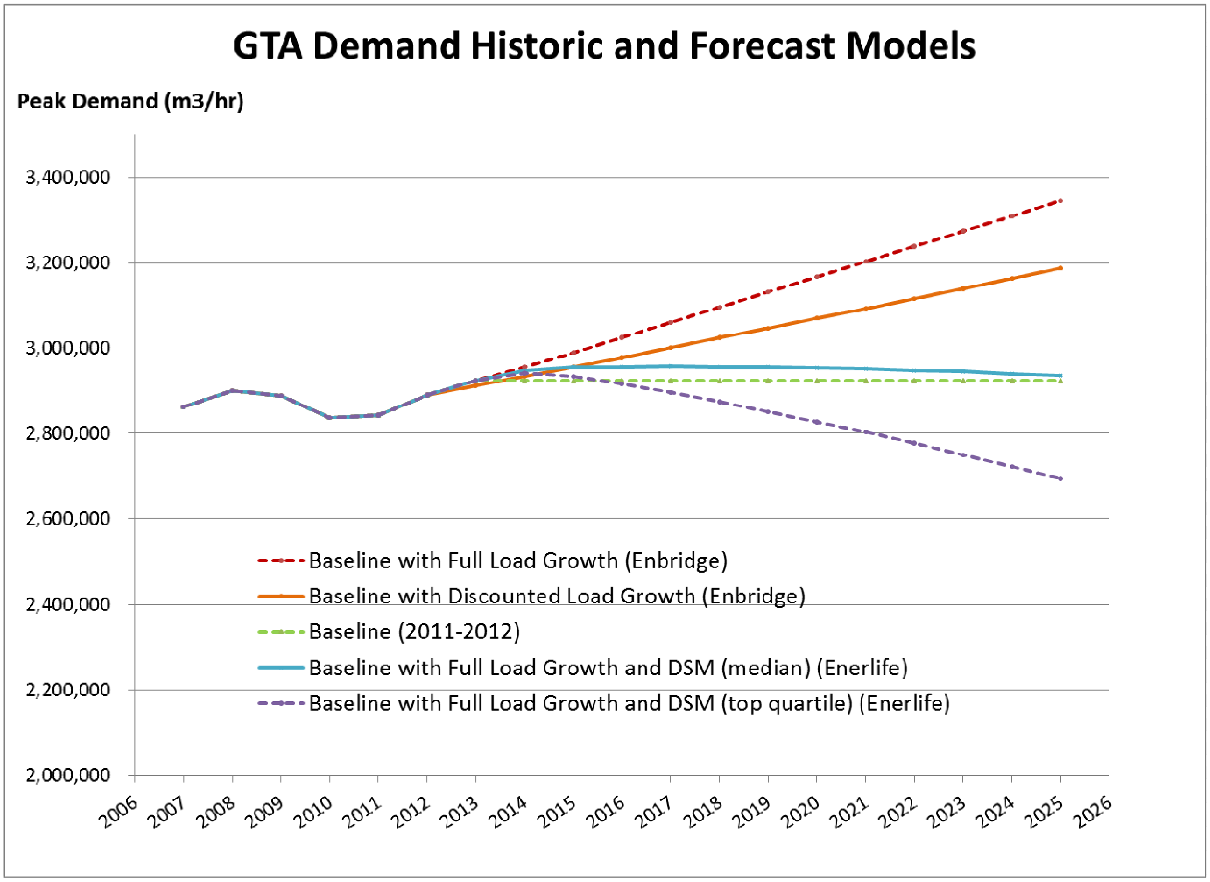


Figure 6 Comparison of savings and increases in gas use by 2025 from 2011 Baseline in the GTA Demand Historic and Forecast Models

% Increase by 2025 from 2012 Baseline	**Apartment**	**Commercial**	**Industrial**	**Residential**	**Total**
Enbridge's Full Growth Model	18.8%	13.6%	0.6%	19.1%	15.8%
Enbridge's Discounted Growth Model	12.2%	8.9%	0.4%	12.4%	10.3%
Enerlife's Forecast with Full Growth and DSM (median)	3.7%	-8.3%	-14.5%	12.9%	1.6%
Enerlife's Forecast with Full Growth and DSM (top quartile)	-15.8%	-22.6%	-14.5%	12.9%	-6.7%
% Reduction by 2025 from Enbridge's Full Growth Model					
Enerlife's median DSM	-12.7%	-19.3%	-15.0%	-5.2%	-12.2%
Enerlife's top quartile DSM	-29.1%	-31.9%	-15.0%	-5.2%	-19.5%

Figure 7 Median and Top Quartile DSM volume

	Median Target		Top Quartile Target	
	DSM per year (m3/hr)	% of annual volume	DSM per year (m3/hr)	% of annual volume
2014	8,929	0.3%	14,287	0.5%
2015	25,654	0.9%	40,995	1.3%
2016	34,321	1.2%	54,518	1.7%
2017	35,075	1.2%	55,751	1.8%
2018	35,761	1.2%	56,859	1.8%
2019	36,477	1.2%	58,019	1.8%
2020	37,192	1.2%	59,176	1.8%
2021	37,921	1.2%	60,349	1.8%
2022	38,653	1.2%	61,527	1.8%
2023	39,376	1.2%	62,696	1.9%
2024	40,099	1.2%	63,864	1.9%
2025	39,687	1.2%	62,783	1.7%

2.4 Building Sector Peak Demand Models

The following are the individual building sector models that inform the GTA Peak Demand Model, utilizing the same methodology.

Figure 8 Apartment Sector Peak Demand Model

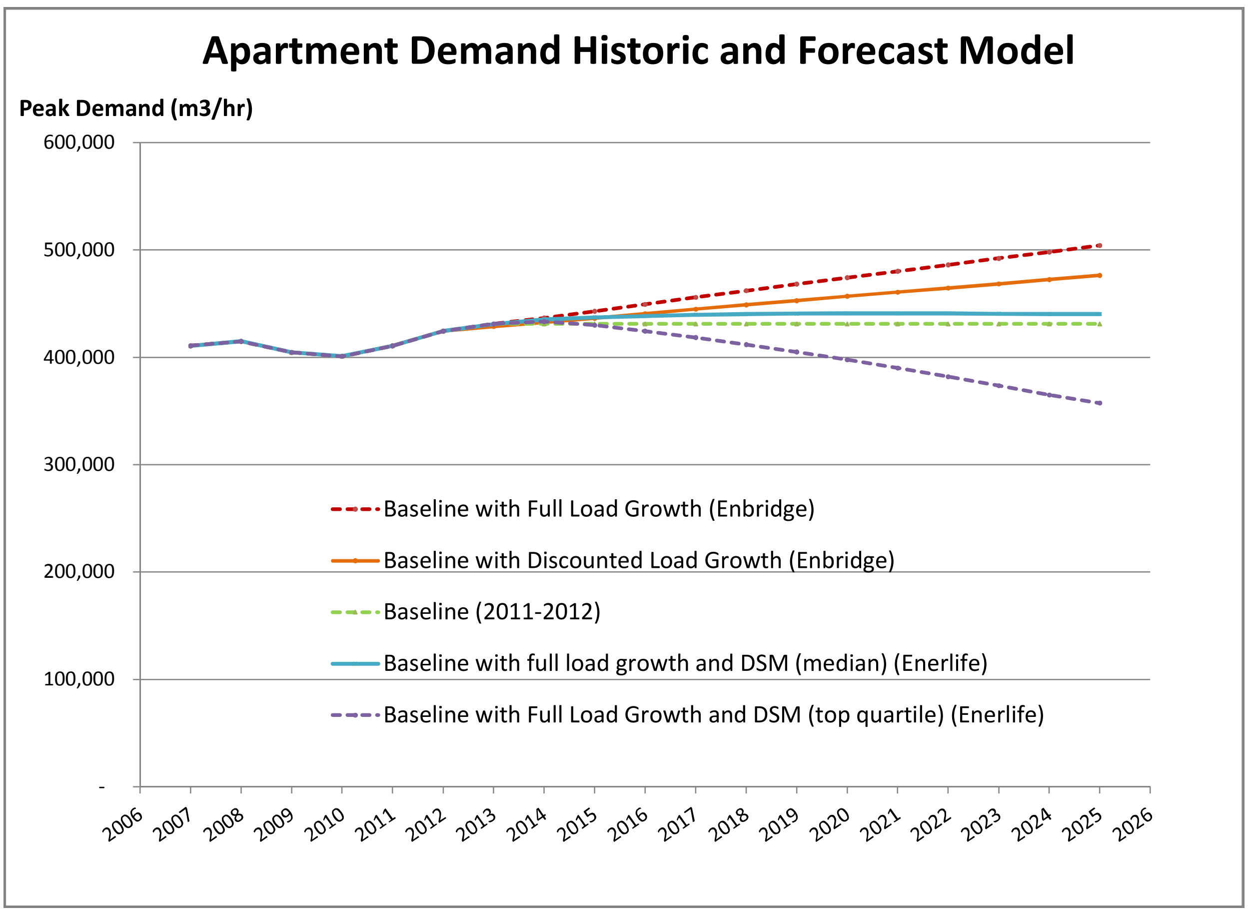


Figure 9 Commercial Sector Peak Demand Model

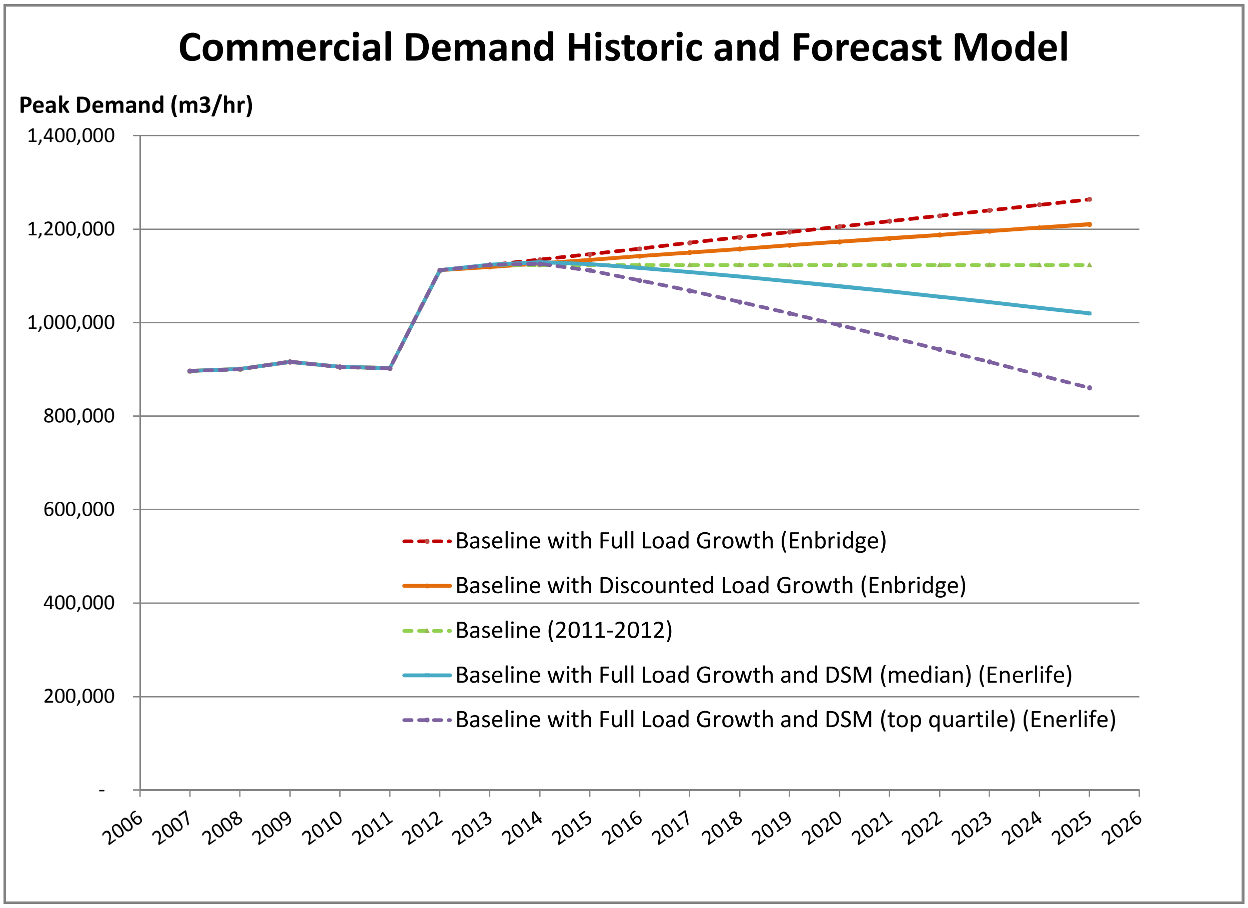


Figure 10 Industrial Sector Peak Demand Model

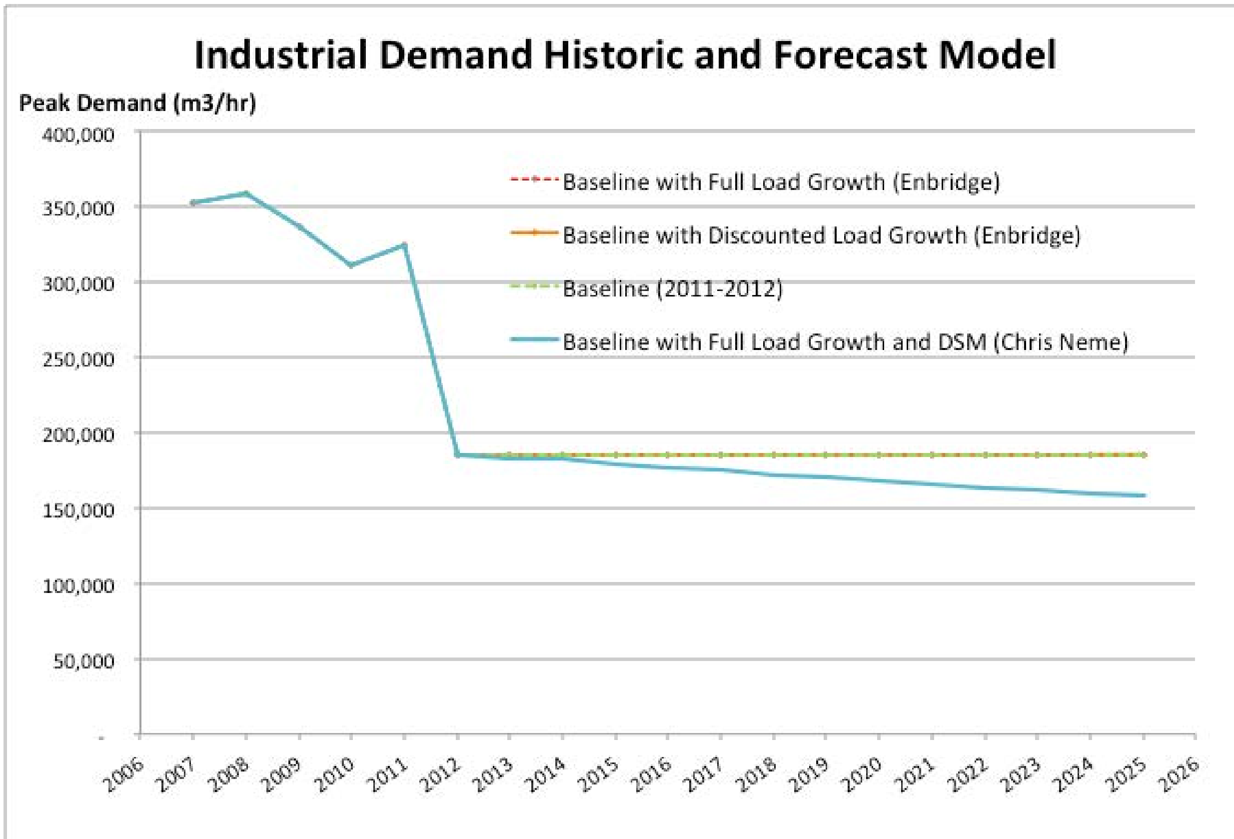
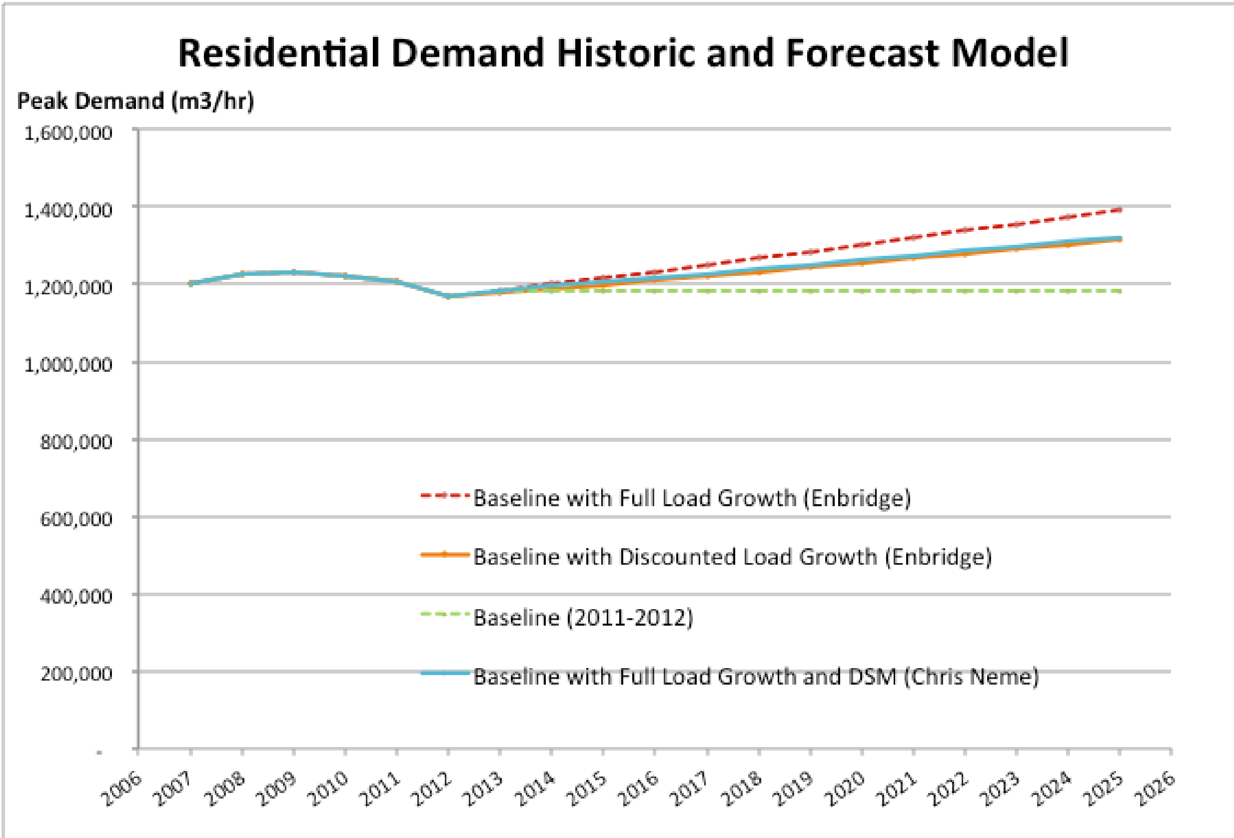


Figure 11 Residential Sector Peak Demand Model



Part Three – Performance-based conservation

3.1 Performance based conservation

Performance based conservation begins with identifying high energy intensity buildings through benchmarking and then works systematically towards identifying and fixing the particular inefficiencies causing the high use in each building. The nature of the inefficiencies runs the range of errors in design and construction, through equipment deterioration over time, to changes in use and operation of the building, and poor performance of controls and automation systems. It is the compound effect of these problems that leads to gas use levels in some buildings which is 3 to 5 times what is needed and already achieved by comparable, more efficient buildings.

Fixing these problems requires a systematic methodology. The work involved in equipment repairs and replacement, right-sizing and rebalancing, refurbishment and re-programming, typically provides relatively short payback periods.

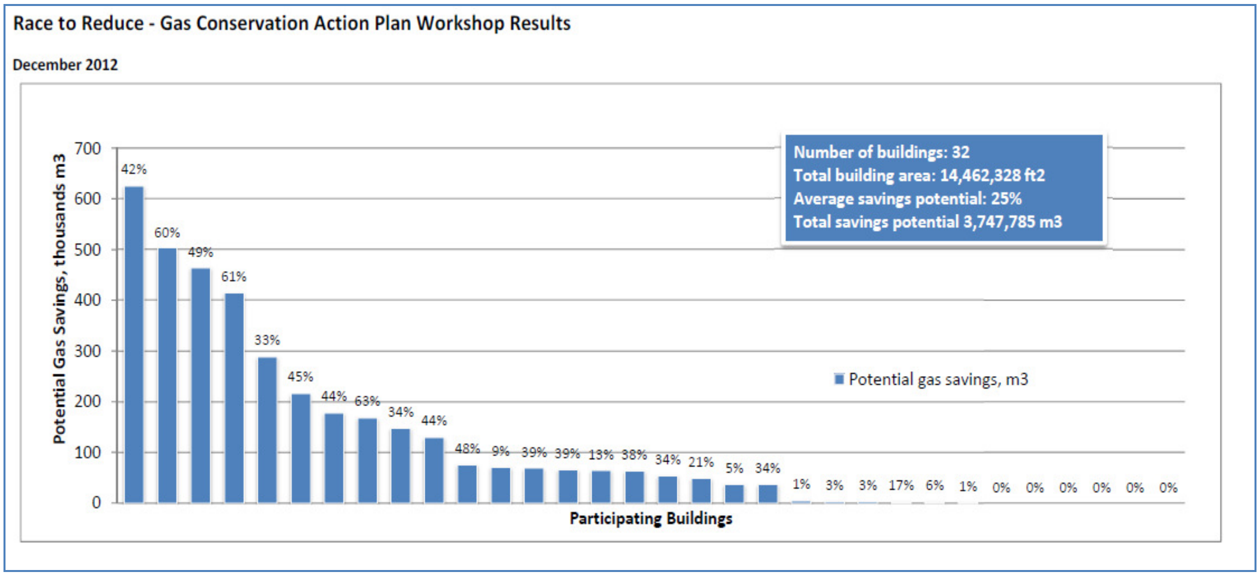
Part Four – Achieving the Additional DSM Savings

4.1 Identify Top Savings Potential Buildings

Performance-based conservation begins with identification of buildings with the greatest potential for savings and level of reduction possible. Enerlife piloted this approach in 2012 on behalf of Enbridge, through a workshop provided to Race to Reduce participants that addressed 31 commercial office buildings with a total area of over 14 million square feet.[9] Benchmarking and target-setting identified the range of gas savings potential shown in the chart below. The analysis for each building was provided to the participant in a standardized energy assessment report. The workshop then provided training in which specific measures were indicated to achieve the targeted savings in each building, enabling each participant to produce their own customized gas conservation action plan, and enabling Enbridge Energy Solutions Consultants to follow up with technical and incentive support to deliver the savings.

[9] Enbridge Energy Efficiency Workshop, November 23rd, 2012

Figure 12 Commercial office building gas savings potential[10]



This illustrates the importance of identifying buildings in each sector with the greatest potential gas savings. Some buildings have significant gas reduction potential while others have little or none at all. Applying a similar approach across each building sector will enable Enbridge to focus its efforts on customers and buildings with the greatest DSM potential, and help them identify the specific actions and measures which will achieve the savings results.

Our proposed plan envisages Enbridge targeting building owners of large buildings and large portfolios of buildings, based on their gas savings potential identified through benchmarking and target-setting. Commercial building owners already collaborate in energy efficiency initiatives such as REALpac Energy Benchmarking, BOMA BESt, Race to Reduce and Greening Health Care, which support awareness and engagement. Once owners are engaged and their buildings assessed, technical support can be provided by Enbridge assisting them in identifying contributing factors to high gas use, implementing necessary improvements and verifying that savings are achieved and maintained over time. Enbridge was unable to provide the requested breakdown of numbers of customers accounting for the largest gas consumption.1

However, consistent with this strategy, we have refined our recommended approach to market engagement and penetration using gas savings potential data for commercial buildings from our database. The strategy is illustrated below, which lays out the first four years of a 12-year market engagement program. The following 8 years of the program would build on this foundation to achieve the modeled top-quartile gas savings of 822 million M3/year in 2025.

[10] Labelled percentages in the graph indicate the gas savings potential for each individual building.

The proposed strategy is to engage buildings in each year of the program with a combined 75 million M3/year of gas savings potential so, by the end of 11 years, the required 2025 top quartile total of 822 million M3/year (as presented in the model) will be achieved.

The first year of the program would target owners of large buildings – typically hospitals, major commercial and government office buildings and hotels, and universities. Our database contains 26 such buildings in the GTA (including office buildings in the Enbridge workshop for the Race to Reduce as shown in Exhibit L.EGD.ED.1, Figure 12, Page 13) owned by 20 different organizations with identified potential savings totaling 24 million M3/year. Based on this, the program would aim to engage approximately 60 owners and identify approximately 80 high gas savings potential buildings to achieve the target engagement of buildings with combined potential for 75 million M3/year.

We estimate our database contains fewer than 20% of the large gas savings potential buildings in the GTA. The market engagement program would engage these buildings and other readily identified owners to meet the first year's target. Gas savings would be realized over the following 2-3 years.

The second year would target buildings with 200,000 M3/year of gas savings potential. Our database of office, government and commercial office buildings contains 25 of these buildings with a combined gas savings potential of 6.6 million M3/year. To meet the aims of the program requires approximately 300 of these buildings. However, large portfolio owners, such as school boards, municipalities and retail chains, would be targeted first so the number of owners to engage is proportionately less (estimated at 50).

The subsequent year of the program would target buildings with 10,000 M3/year gas savings potential, requiring engagement of 500 buildings and 50 new customers (given that some customers engaged in years one and two will have buildings already identified in this range). The fourth year would focus on buildings with 50,000 M3/year gas savings potential, for which we estimate 1000 buildings and 50 new customers. Successful execution of this proposed strategy for the first four years will establish the relationships, processes and capabilities required in subsequent years of the program.

Table 1 Market Penetration Model for Commercial Sector

	Year 1	**Year 2**	**Year 3**	**Year 4**
Gas savings engaged (M3)	75 million	75 million	75 million	75 million
Potential savings per building M3/yr.	> 500,000	> 200,000	> 100,000	> 50,000
# of targeted buildings/year	80	300	500	1000
# of new participants/yr.	60	50	50	50

Target customers	Commercial landlords; major hospitals; universities; major hotels; government	School boards (high schools); municipalities; colleges; large retail; other hospitals, hotels etc	Other retailers; long-term care operators	Banks (branches); school boards (primary schools);

The Apartment sector also has large buildings, large portfolio owners, and collaborative programs in place (including the Federation of Housing Providers of Ontario, and the City of Toronto Tower Renewal Office) so a similar model would apply. A s.

Lower penetration rates are projected in the model for Residential and Industry, but the principles of performance-based conservation may be useful in these sectors as well.

4.2 Finding and Fixing Inefficiencies

Identifying and addressing inefficiencies requires a savings focused approach to DSM. Trained people with similar skill sets to energy analysts, commissioning agents and energy efficiency engineers focused on getting to energy savings as quickly as possible are needed to work with building operation staff. Outcomes-based strategies and incentives prioritize scheduling optimization, ventilation and air flow testing and savings opportunities that use lower cost technology such as zone dampers and variable frequency drives. These typically can be implemented quickly and have short paybacks.

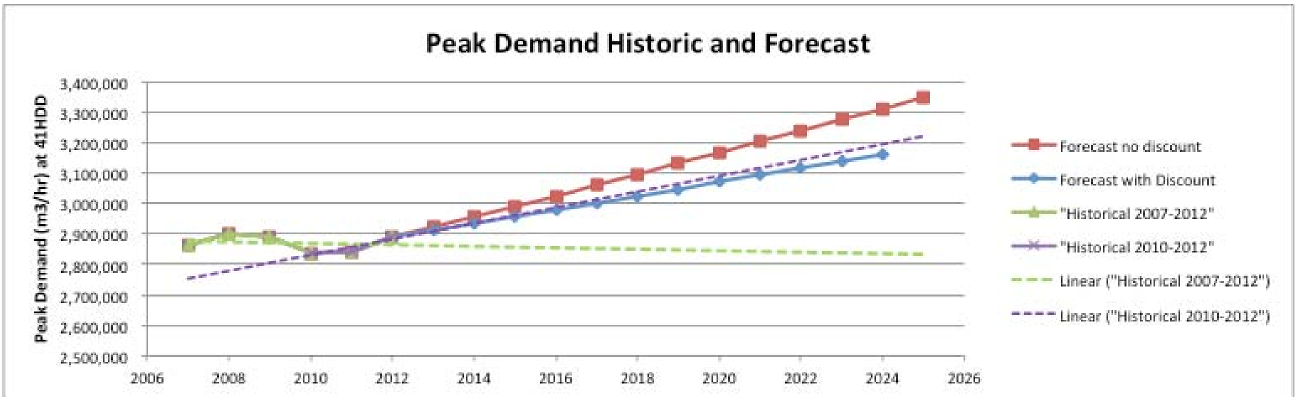
Part Five - Enbridge Peak Demand Forecast Model

5.1 Assessment of Enbridge's Load Growth Forecast Model

Enbridge's argument for a proposed new pipeline to serve the GTA is partially based on the need for additional capacity to meet increased peak hourly demand. To support this, they provided a Peak Load Growth Forecast discounted for gas savings from DSM programs. Due to the short length of review time, we are unable to provide a complete assessment of the load forecast but have the following observations:

a. Insufficient trend information to base projection

Figure 13 Peak Demand Trends



The derived historic peak demand (weather-normalized to 41HDD)[11] from between 2007 and 2012 shows no net growth overall. However, Enbridge's forecast indicates an increase in demand. This is consistent with a shorter data period (2010 to 2012). Given the erratic growth patterns within the Industrial and Commercial sectors during this time, three years would seem insufficient to base a forecast upon. [12]

As illustrated below, the industrial sector demand dropped by 43% between 2011 and 2012 while the commercial sector demand increased by 23% in the same period with no significant increase in the number of customers. Overall there was little total demand growth. This would indicate the difficulty in forecasting future growth based on so little trend data.

Table 2 Number of Customers by Sector (historical)

	Apartment m^3/hr	Commercial m^3/hr	Industrial m^3/hr	Residential m^3/hr	Total m^3/hr
2007	410,758	896,792	352,178	1,203,076	2,862,804
2008	414,932	900,775	358,798	1,225,376	2,899,881
2009	404,701	916,271	336,968	1,230,241	2,888,181
2010	400,992	905,314	311,336	1,220,411	2,838,053
2011	410,716	**902,621**	**324,351**	1,205,503	2,843,191
2012	424,455	**1,112,231**	**184,774**	1,168,523	2,889,983

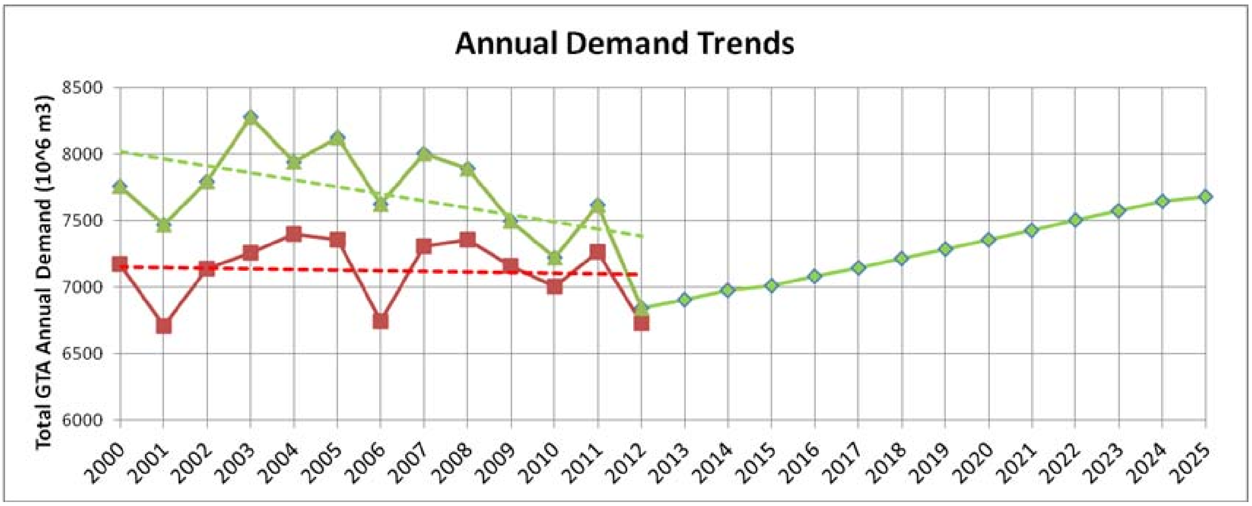
b. Forecast inconsistent with historical peak demand trends

Based on historical annual demand trends, demand has been declining over the past decade but Enbridge has forecast substantial demand growth in the future. As can be seen in the graph below, it

[11] Exhibit I.A4.EGD.ED3
[12] EXHIBIT I.A4.EGD.EGC.ED.3

appears Enbridge provided total GTA annual demand data from two sources. The green line is from actual volumes[13] and the red is measured at the gate station[14]. Neither indicates a growth in demand, while the annual demand is forecast to grow consistently. During the historical period (2004 to 2012) the growth rate of the number of customers is similar to the forecasted customer growth rate, yet there was no peak demand growth. Enbridge uses linear interpolation between annual consumption to derive peak hourly data, which supports the correlation between annual volume and peak hourly demand. Based on this, there is no historical correlation between an increase in number of customers and significant peak demand growth as forecast.

Figure 14 Annual Demand Trends - historic and forecast



c. Inaccurate application of the discount factor

The application of the discount factor in the Enbridge Load Growth Forecast model appears to be misleading. The DSM forecast of 12 10^3m^3/hr reduction each year is 0.4% of the peak hourly load in GTA. The 35% discount factor is applied on the incremental **new** customer growth rate of 1.2% (35 10^3m^3/hr) each year, to account for the DSM load reduction over the entire **existing** building stock. This leads to the misunderstanding that no amount of DSM could offset growth, since even if a 99% discount is applied there will still be a positive growth trend.

It would be more accurate to apply the discount factor directly to the total peak load. The Performance-based DSM model proposed in this report applies it this way, and if DSM reaches 3 times the current level there will be no net growth.

[13] JT2.36 using “actual volumes from Franchise Areas 10, 20, 30 from the billing system to proxy for volumes in the GTA Project Influence Area” for the historical information, and the “2013 Board-approved average use were applied to GTA Project influence area customer growth forecasts to project total annual demands”
[14] Exhibit I.A4.EGD.ED.25, “measured at the gate station”

Appendix A

Terms of Reference

Environmental Defence asks that you:

1. Quantify the demand side management (DSM) potential in large multi-residential, commercial and institutional buildings that can be pursued by Enbridge Gas Distribution Inc. ("Enbridge") to potentially defer or avoid the need for part or all of the proposed GTA pipeline. Please quantify the DSM potential in TJ/day on peak demand day and TJ/year for each year from 2014 to 2025 inclusive, for existing and new buildings, and in the geographical area that Enbridge states in its interrogatory responses that further capacity is required;
2. Quantify the net present value of the DSM potential;
3. Outline how Enbridge could capture this DSM potential (e.g., larger financial incentives for customers that save natural gas);
4. Contrast this potential to the current 'business as usual' DSM offering of Enbridge for these customer groups as set out in its growth forecast and interrogatory responses in this proceeding;
5. Provide an assessment and critique of Enbridge's demand forecast, including of its underlying methodology, assumptions, and inputs; and
6. Prepare an alternative demand forecast that remedies any problems you have identified with respect to Enbridge's forecast (if any), provide an estimate of demand to 2025 based on the amount of DSM assumed by Enbridge in its evidence, and provide an estimate of demand to 2025 based on potential incremental DSM, as discussed above.

Appendix B

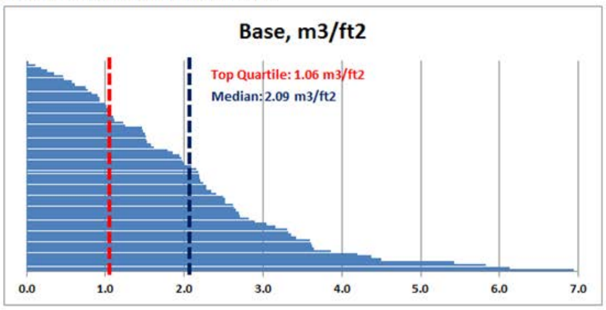
The following are the Building Sector Benchmarking reports:

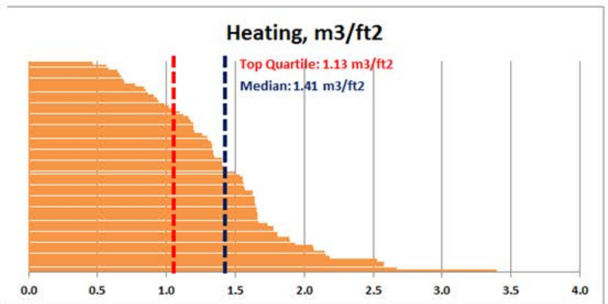
Sector: Hospitals

Number of buildings: 77
Total building area, ft2: 29,888,023

Gas usage	Savings potential, % at the attainment of	
	Median	Top Quartile
Base	22%	52%
Heating	12%	25%
Total	**18%**	**41%**

Based on 2010 data weather-normalized to Toronto.



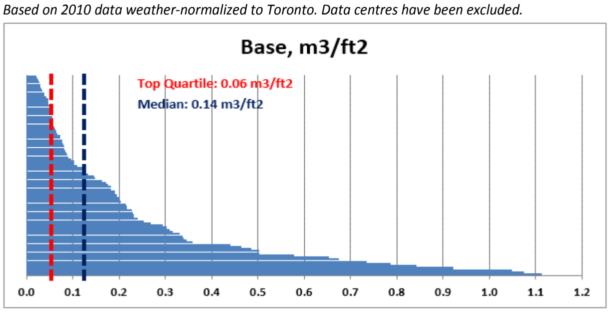


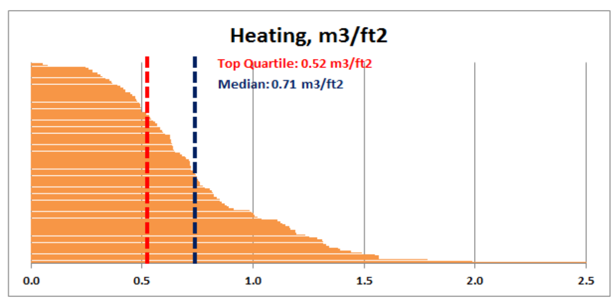
Sector: Office Buildings

Number of buildings: 123
Total building area, ft2: 42,000,827

Gas usage	Savings potential, % at the attainment of	
	Median	Top Quartile
Base	47%	72%
Heating	23%	39%
Total	**27%**	**44%**

Based on 2010 data weather-normalized to Toronto. Data centres have been excluded.



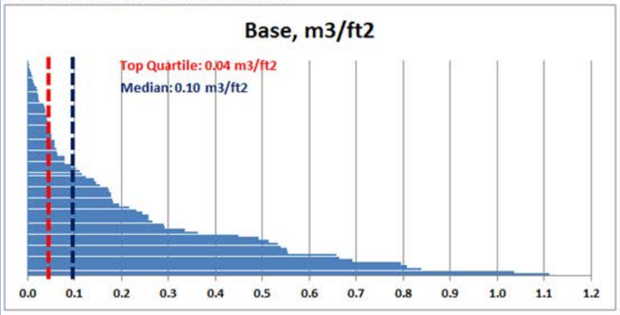


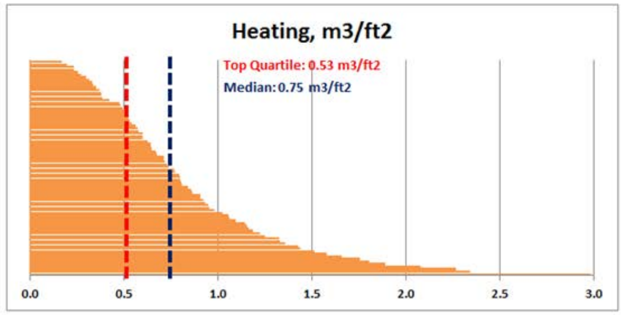
Sector: Retail Branches

Number of buildings: 84
Total building area, ft2: 730,478

Gas usage	Savings potential, % at the attainment of	
	Median	Top Quartile
Base	72%	87%
Heating	26%	42%
Total	**37%**	**53%**

Based on 2009 data weather-normalized to Toronto.



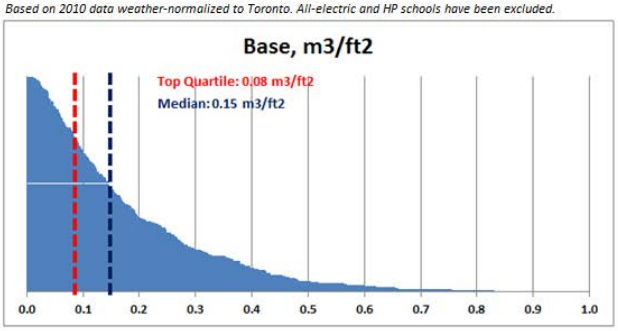


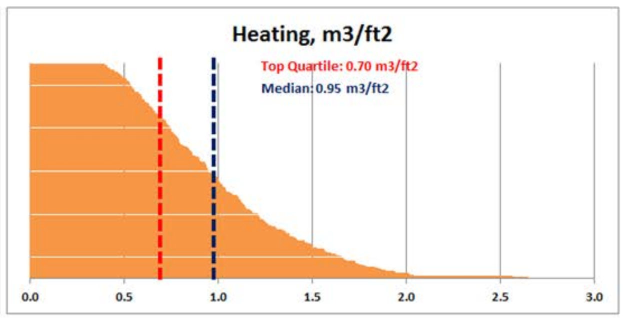
Sector: K-12 Schools

Number of buildings: 212
Total building area, ft2: 12,599,060

Gas usage	Savings potential, % at the attainment of	
	Median	Top Quartile
Base	44%	63%
Heating	17%	32%
Total	**21%**	**37%**

Based on 2010 data weather-normalized to Toronto. All-electric and HP schools have been excluded.



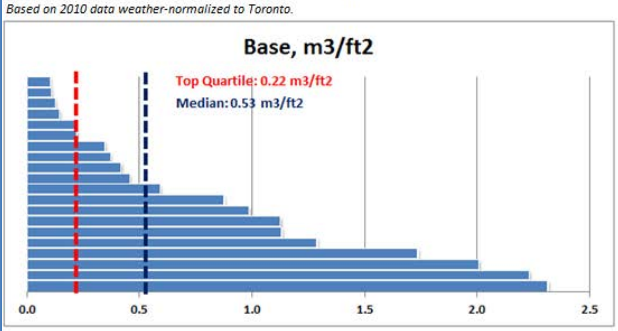


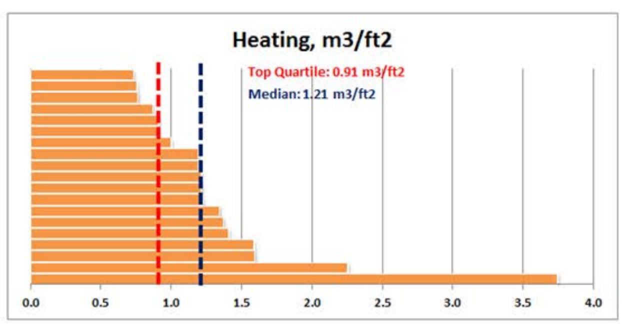
Sector: Recreation

Number of buildings: 20
Total building area, ft2: 1,470,716

Gas usage	Savings potential, % at the attainment of	
	Median	Top Quartile
Base	56%	79%
Heating	12%	29%
Total	**32%**	**52%**

Based on 2010 data weather-normalized to Toronto.



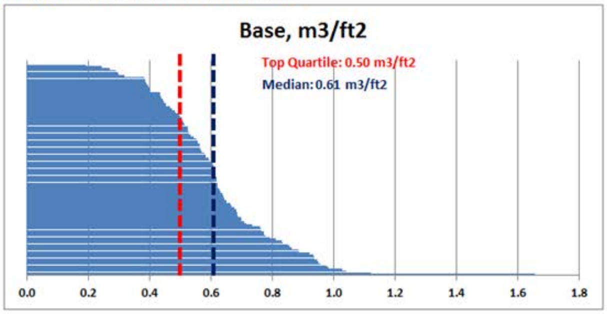


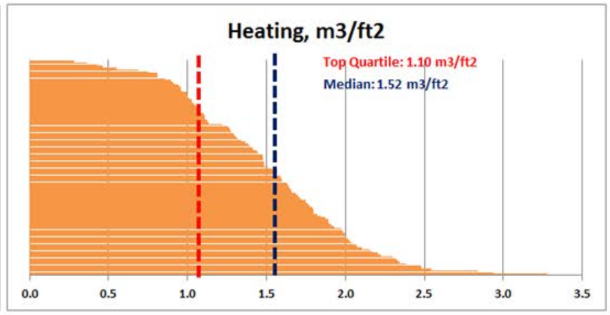
Sector: Multi-Res

Number of buildings:	122
Total building area, ft2:	25,023,702

Gas usage	Savings potential, % at the attainment of	
	Median	Top Quartile
Base	12%	23%
Heating	13%	30%
Total	**13%**	**28%**

Based on 2012-11 data weather-normalized to Toronto.





ONTARIO ENERGY BOARD

EB-2012-0451

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

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

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

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Wen Jie Li and I am a Junior Project Engineer at Enerlife Consulting Inc.

2. I have been engaged by or on behalf of Environmental Defence to provide evidence in relation to the above-noted proceeding.

3. I acknowledge that it is my duty to assist the Board impartially by giving evidence that is fair and objective and to abide by the requirements set out in Rule 13A of the Ontario Energy Board *Rules of Practice and Procedure*. I am aware of and accept the responsibilities set out in that Rule.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date: June 18, 2013 Signature: Wj Li

ONTARIO ENERGY BOARD

EB-2012-0451

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

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

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ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Gillian Henderson and I am a Principal at Enerlife Consulting Inc.

2. I have been engaged by or on behalf of Environmental Defence to provide evidence in relation to the above-noted proceeding.

3. I acknowledge that it is my duty to assist the Board impartially by giving evidence that is fair and objective and to abide by the requirements set out in Rule 13A of the Ontario Energy Board *Rules of Practice and Procedure*. I am aware of and accept the responsibilities set out in that Rule.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date: June 18/2013

Signature: [signature]

ONTARIO ENERGY BOARD

EB-2012-0451

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ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Ian Jarvis and I am the President of Enerlife Consulting Inc.

2. I have been engaged by or on behalf of Environmental Defence to provide evidence in relation to the above-noted proceeding.

3. I acknowledge that it is my duty to assist the Board impartially by giving evidence that is fair and objective and to abide by the requirements set out in Rule 13A of the Ontario Energy Board *Rules of Practice and Procedure*. I am aware of and accept the responsibilities set out in that Rule.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date: June 18th 2013.   Signature: ____________

Climate, Environment, and the IMF

Stabilizing atmospheric concentrations of greenhouse gases will require a radical transformation of the global energy system over coming decades. Fiscal instruments (carbon taxes or similar) are the most effective policies for reflecting environmental costs in energy prices and promoting development of cleaner technologies, while also providing a valuable source of revenue (including, not least, for lowering other tax burdens). Fiscal policies also have a key role to play in addressing other environmental challenges, like poor air quality and urban congestion. Getting energy prices right has large fiscal, environmental, and health benefits, and need not wait on global action.

Responding to climate change has become one of the world's foremost policy challenges. In line with its mandate and expertise, the IMF focuses on the fiscal, financial, and macroeconomic challenges of climate change. The IMF also provides advice on the appropriate design of fiscal reforms to promote greener growth more broadly, particularly with regard to the practicalities of getting prices right in energy and transportation systems to reflect a broad range of environmental costs.

Fiscal implications

Broad-based charges on greenhouse gas emissions, such as a carbon tax, are the most effective instruments for encouraging businesses and individuals to reduce energy use and switch to cleaner fuels.

Carbon taxes can also raise substantial amounts of government revenue. Fiscal challenges created by current economic difficulties provide an opportune time to consider these types of innovative environmental charges.

Cap-and-trade systems are another option, but generally they should be designed to look like taxes through revenue-raising and price stability provisions.

Designing a response

There are many issues to consider in designing fiscal policies to mitigate climate change:

- the appropriate tax level and base, and the treatment of traded goods;
- the role of complementary technology policies;
- the balance between carbon and other taxes in financing the government's budget and how to use the additional revenues;
- the treatment of forestry and other non-energy emissions; and
- how to address impacts on vulnerable households and firms.

These and other issues are discussed at length in a 2012 IMF book, Fiscal Policy to Mitigate Climate Change: A Guide for Policymakers. In 2015 the IMF (with the Brookings Institution and Resources for the Future) will publish an edited volume focused specifically on the design of a U.S. carbon tax in the context of broader fiscal reform.

Financing responses to climate change

There is broad agreement that substantial financial assistance is needed for climate adaptation and mitigation projects in developing countries. In 2011, the IMF, in collaboration with the World Bank and others, undertook a study for the G-20 on the effectiveness, revenue potential, and administration, of a wide range of fiscal options for climate finance. This included analysis of potential charges for international aviation and maritime emissions and domestic (carbon-related and other) fiscal instruments.

An IMF staff proposal for a Green Fund would facilitate financial flows to developing countries' to assist in their efforts on climate change adaptation and mitigation. The Green Fund would be neither created nor managed by the IMF itself. It would play an important role as a framework to mobilize resources, and could be the first step toward a binding global agreement on reducing greenhouse gas emissions.

Macroeconomic challenges

Climate change mitigation policies affect countries' economic growth, saving and investment levels, capital flows, and exchange rates. But IMF analysis suggests these costs are manageable if policies are well designed. In particular, policies should be credible and provide long-term price stability, flexible enough to be able to adjust to emerging information and changing economic conditions, and implemented as broadly and equitably as possible.

Other environmental work in the IMF

There is also ample scope for reforming tax systems to deal much more effectively with broader environmental and related problems that can be a significant drag on economic growth, such as the health and productivity impacts of poor air quality, and severe congestion of major urban centers. The key challenges are to restructure existing energy tax systems to target directly the source of environmental harm (e.g., by taxing emissions or driving on busy roads rather than electricity consumption or vehicle sales), to better align tax levels with the scale of environmental harm, and to overcome practical challenges of higher energy and transportation costs.

Earlier IMF papers lay out core principles of green tax design and focus on case studies for Chile and Mauritius. And a 2014 IMF report (covering over 150 countries) provides estimates for taxes on fossil fuel products to reflect pollution and other environmental impacts associated with energy use and underscores the large environmental, health, and fiscal benefits from tax reform—reforms which are often in countries' own interests, even leaving aside climate issues.

A recent IMF paper and book published in September 2013 put the magnitude of subsidies for fossil fuel energy sources at about $2 trillion worldwide in 2011, including both direct fiscal costs and implicit subsidies from the failure to charge for environmental damages or tax energy at the same rate as other consumption products. The paper and book draw on case studies to provide practical guidance (e.g., on better targeted instruments commonly available to protect the poor) for implementing energy price reform. In the case of petroleum products for example, reducing subsidies could significantly reduce greenhouse gas emissions in many countries, while at the same time reducing fiscal deficits. The IMF is also involved in updating these estimates. Another recent study defines and measures the concept of "green investment" and explains recent trends.

The Premier
of Ontario

Legislative Building
Queen's Park
Toronto, Ontario
M7A 1A1

La première ministre
de l'Ontario

Édifice de l'Assemblée législative
Queen's Park
Toronto (Ontario)
M7A 1A1

Ontario

September 25, 2014

The Honourable Glen Murray
Minister of the Environment and Climate Change
77 Wellesley Street West
11th Floor, Ferguson Block
Toronto, Ontario
M7A 2T5

Glen

Dear Minister Murray:

I am honoured to welcome you to your role as Minister of the Environment and Climate Change. We have a strong Cabinet in place, and I am confident that together we will build Ontario up, create new opportunities and champion a secure future for people across our province. The people of Ontario have entrusted their government to be a force for good, and we will reward that trust by working every day in the best interests of every person in this province.

As we implement a balanced and comprehensive plan for Ontario, we will lead from the activist centre. We will place emphasis on partnerships with businesses, communities and people to help foster continued economic growth and make a positive impact on the lives of every Ontarian. This collaborative approach will shape all the work we do. It will ensure we engage people on the issues that matter the most to them, and that we implement meaningful solutions to our shared challenges.

Our government's most recent Speech from the Throne outlined a number of key priorities that will guide your work as minister. Growing the economy and helping to create good jobs are fundamental to building more opportunity and security, now and in the future. That critical priority is supported by strategic investments in the talent and skills of our people, from childhood to retirement. It is supported through the building of modern infrastructure, transit and a seamless transportation network. It is supported by a dynamic business climate that thrives on innovation, creativity and partnerships to foster greater prosperity. And it is reflected across all of our government, in every area, and will extensively inform our programs and policies.

As we move forward with our plan to grow the economy and create jobs, we will do so through the lens of fiscal prudence. Our 2014 Budget reinforces our commitment to balancing the budget by 2017-18; it is essential that every area adheres to the program-spending objectives established in it. We will choose to invest wisely in initiatives that strengthen Ontario's competitive advantage, create jobs and provide vital public services to our families. The President of the Treasury Board, collaborating with the Minister of Finance, will work closely with you and your fellow Cabinet members to ensure that our government meets its fiscal targets. The President of the Treasury Board will also lead the government's efforts on accountability, openness and modernization as we implement new accountability measures across government.

.../2

As Minister of the Environment and Climate Change, you will continue to focus your attention on ensuring clean air, water and land. You will also work with industry, stakeholders and the public to achieve compliance with environmental standards and you will establish a new long-term climate change strategy.

Your ministry's specific priorities include:

Moving Forward on Climate Change

- Building on, and supporting, the most current science, lead the development of a new long-term climate change strategy for Ontario. This strategy will be forward looking to 2050 and will contain an action plan to help our government achieve its greenhouse gas reduction targets for 2020. Implementing the strategy and achieving our targets will require an all-of-government approach and, as Minister of the Environment and Climate Change, you will work with and be supported by colleagues, including the ministers of Finance, Energy, Transportation, Municipal Affairs and Housing, Economic Development, Employment and Infrastructure, Agriculture, Food and Rural Affairs, Research and Innovation, and Natural Resources and Forestry to complete the strategy in 2015.

- Developing initiatives to engage the broader public and stakeholders in a discussion about climate change and its risks.

- Supporting the Secretary of the Cabinet and the President of the Treasury Board to ensure climate change is taken into account in the government decision-making process. This will include greenhouse gas (GHG) impact analyses for significant policies, legislation and regulations and adaptation considerations for public infrastructure investments.

- Supporting the Minister of Intergovernmental Affairs and the Minister of Energy, and working with other provinces and territories, on the development of a Canadian Energy Strategy that includes co-ordinated efforts to reduce GHG emissions.

- Developing new alternative fuel rules in 2014 to help big, energy-intensive industries reduce their GHG emissions.

Protecting the Great Lakes

- Re-introducing a strengthened *Great Lakes Protection Act*, which recognizes the importance of the Great Lakes to Ontario's environment, economy and the health of our citizens.

- Further protecting the Great Lakes, including making Great Lakes shorelines and beaches cleaner and safer, through steps outlined below.

- Negotiating the renewal of, and implementing, the Canada-Ontario Agreement respecting the Great Lakes Basin Ecosystem. This will include developing a nutrient target by 2016 to address algal blooms in the Great Lakes and bringing forward recommendations to meet that target.

- Continuing to engage local communities in clean-up and restoration efforts, including through the Great Lakes Guardian Fund.
- Working with Great Lakes states to ensure the sustainability of the Great Lakes. This will include fully implementing the Great Lakes – St. Lawrence River Basin Sustainable Water Resources Agreement by regulating intra-basin transfers.

Increasing Waste Diversion

- Developing and implementing improved approaches to waste diversion. Your ministry will do so by building on the release of the Waste Reduction Strategy and working with industry, municipalities and other stakeholders toward the objective of re-introducing waste reduction legislation. The goal for your ministry is to ensure the ongoing sustainability and appropriate governance of waste diversion programs. This is critical to protecting the environment, recovering economic value in the waste stream and reaping GHG reduction benefits by using resources more efficiently.

Improving Drinking Water for First Nations

- Improving drinking water on reserves, with a focus on remote communities: the number of First Nation reserves without access to safe drinking water is unacceptable. You will work with the Minister of Aboriginal Affairs, me — in my capacity as Minister of Intergovernmental Affairs — and the federal government, who are primarily responsible for the provision of safe drinking water on reserves, to make substantive progress in this area. We will develop measurable, achievable targets to monitor progress.

Improving Pollinator Health

- Supporting the Minister of Agriculture, Food and Rural Affairs in efforts to strengthen pollinator health.

Safeguarding People from Toxics

- Working with business, industry and partner ministers to provide Ontarians with better information about chemicals linked with cancer.
- Working with industry, ensure that products on Ontario store shelves such as children's products are as safe as those in the US and the European Union.

Supporting the Development of the Ring of Fire

- Continuing to work on decisions relating to environmental assessments associated with projects in the Ring of Fire region. You will do so by working with the ministers of Northern Development and Mines, Aboriginal Affairs, and Natural Resources and Forestry. This will include ensuring that the regional and cumulative impacts of proposed development are considered.

.../4

Enhancing Polluter Responsibility

- Reviewing the legislative framework to ensure there is a comprehensive approach to holding polluters responsible for decisions that affect the environment. Your ministry will put greater emphasis on prevention and on the "polluter pays" principle, focusing initially on contaminated sites.

We have an ambitious agenda for the next four years. I know that, by working together in partnership, we can be successful. The above list of priority initiatives is not meant to be exhaustive, as there are many other responsibilities that you and your ministry will need to carry out. To that end, this mandate letter is to be used by your ministry to develop more detailed plans for implementation of the initiatives above, in addition to other initiatives not highlighted in this letter.

I ask that you continue to build on the strong relationships we have with the Ontario Public Service, the broader public sector, other levels of government, and the private, non-profit and voluntary sectors. We want to be the most open and transparent government in the country. We want to be a government that works for the people of this province — and with them. It is of the utmost importance that we lead responsibly, act with integrity, manage spending wisely and are accountable for every action we take.

I look forward to working together with you in building opportunity today, and securing the future for all Ontarians.

Sincerely,

Kathleen

Kathleen Wynne
Premier

ICF MARBEK NATURAL GAS ENERGY EFFICIENCY POTENTIAL STUDY

2008 Natural Gas Energy Efficiency Potential Study

with 2011 Summary Report Update

Submitted to

Union Gas Ltd

Submitted by

ICF Marbek

Reports and Appendices – March 2009

Summary Report – July 2011

Table of Contents

Marbek

Natural Gas Energy Efficiency Potential
Residential, Commercial and Industrial Sectors

Summary Report – Update 2011

Project
114103

Submitted to
Union Gas Distribution

Submitted by
ICF Marbek

July 2011

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Table of Contents

List of Exhibits

1 Introduction

1.1 Background

Union Gas Ltd. (Union) is a natural gas utility serving almost 1.3 million customers in the residential, commercial and industrial markets. Union is a regulated utility with a franchise area spread across the province of Ontario, including northern, southwestern and southeastern cities and towns.

Since 1997, Union has delivered demand side management (DSM) programs to its customers under a mandate from the provincial regulator, the Ontario Energy Board (OEB). Union offers DSM programs to all in-franchise customer rate classes and across all sectors. The DSM savings target and budget are determined through a rate proceeding with the OEB.

Union's customers have become increasingly aware of the importance of energy efficiency in recent years. Similarly, energy efficiency codes and standards have also continued to strengthen, reflecting Ontario's increasing emphasis on energy efficient technologies and buildings. In the eleven year period from 1997 to 2008 Union delivered approximately 614 million m^3 of natural gas savings and over $1 billion in net Total Resource Cost (TRC) benefits.

In the DSM Generic Proceeding held in 2006, Union committed to creating an updated Market Potential Study to be filed with its next multi-year DSM Plan. In 2008, Union initiated this study in preparation for the next generation DSM Framework to begin in 2010. The best available primary economic data for the 2008 study was compiled during the period April to June of 2008. However, the OEB subsequently deferred consideration of the DSM Framework and directed the natural gas utilities to file one year DSM Plans under the existing DSM Framework for 2010 and 2011.

Following completion of the 2008 study, Canada and other global economies entered a period of economic recession, one that could have significant impact on the results of the 2008 study, particularly in the short term. Examples of economic changes that have occurred since the 2008 study was completed and their respective impacts include:

- In January 2009, the Canadian dollar was worth 81 cents U.S. Today the Canadian dollar is worth approximately $1.02. The effect of this on the competitiveness of Ontario manufactured products bound for the U.S. has been serious, limiting the amount of capital available for upgrade projects.

- In January 2009, the natural gas delivered price was approximately $7.50/GJ, having fallen sharply from prices as high as $10.00/GJ only a few months earlier. The outlook for natural gas prices is now approximately $5.50/GJ. This change in price has had the effect of increasing the payback period of all natural gas savings projects, making them harder for natural gas customers to justify.

- Electricity prices have been climbing steadily since 2009, as a result of a changing generation mix and subsidies of renewable energy. The combination of this change in prices and the increase in incentives being offered by the Ontario Power Authority (OPA) and by electricity utilities for electric upgrades means that proportionately less human and financial resources are available to be devoted to natural gas savings projects.

- Multi-national companies with significant presence in Europe and North America are making energy efficient practices a Corporate value, and building in equipment and management standards developed under European energy and carbon pricing scenarios, increasing the uptake of energy efficiency measures.

In light of these considerations, Union commissioned an economic update to the 2008 study in 2011. The purpose of this work was to update the assumptions and baseline data used in the initial 2008 Natural Gas Efficiency Potential Study to better reflect the impacts of economic changes such as those noted. The estimated achievable and economic potential for DSM measures was updated across all applicable technologies, markets and sectors in Union's franchise area. Therefore, the values noted in this summary are updated from those included in the full 2008 report and should be considered best available information.

1.2 Objectives and Scope

Union initiated this study within the context of the conditions noted above. The results of this Natural Gas Efficiency Potential Study will provide a foundation that Union can use into the future to guide the development of its longer-term DSM strategy, including new measures and targets. More specifically, this includes support to Union's application to the Ontario Energy Board regulatory application for the next multi year DSM plan by:

- Estimating the achievable and economic potential for DSM measures across all applicable technologies, markets and sectors in Union's franchise area

- Giving shape to, and refining, ongoing energy efficiency work by Union Gas in order to develop Union's next multi-year DSM plan, and

- Provide information that is actionable and can be easily converted to plan and program development.

The scope of this study is summarized below.

- **Sector Coverage:** The study addresses three sectors: Residential, Commercial[1] and Industrial.

  Geographical Coverage: The study results are presented for the total Union Service Area and for two service regions: Southern and Northern. The Southern region of Union's system extends through Southwestern Ontario from Windsor to just west of Toronto. The Northern region of Union's system extends throughout Northern Ontario from the Manitoba border to the North Bay/Muskoka area and across Eastern Ontario from Port Hope to Cornwall. The study results are disaggregated by service region due to differences in building stock and weather conditions (heating degree days).

- **Study Period**: This study covers a 10-year period. The Base Year is the calendar year 2007, with milestone periods at five-year increments: 2012 and 2017. The Base Year of 2007 was selected, as it was the most recent calendar year for which complete customer data was available when the study was initiated in 2008.

[1] Throughout this report the term "Commercial" also includes institutional sectors, such as schools, hospitals, etc., unless otherwise noted.

- **Technologies:** The study addresses the full range of natural gas energy efficiency measures together with selected renewable energy technologies that are currently commercially available, or are expected to be available within the first 5 years of this study period.

1.2.1 *Data Caveat*

As in any study of this type, the results presented in this report are based on a large number of important assumptions. Assumptions such as those related to the current penetration of energy efficient technologies, the rate of future economic growth and customer willingness to implement new energy efficiency measures are particularly influential.

Wherever possible, the assumptions used in this study are consistent with those used by Union and are based on best available information, which in many cases includes the professional judgement of the consultant team, client personnel and/or local experts. The reader should use the results presented in this report as best available estimates; major assumptions, information sources and caveats are noted throughout the report.

1.3 Definitions

This study employs numerous terms that are unique to analyses such as this one and consequently it is important to ensure that all readers have a clear understanding of what each term means when applied to this study. Below is a brief description of some of the most important terms.

Base Year Natural Gas Use The Base Year is the starting point for the analysis. It provides a detailed description of "where" and "how" natural gas is currently used in each sector. The bottom up profile of energy use patterns and market shares of energy using technologies was calibrated to actual Union customer sales data.

Reference Case Forecast The Reference Case is a projection of natural gas consumption to 2017, in the absence of any new Union DSM market interventions after 2007. It is the baseline against which the scenarios of energy savings are calculated. The Reference case forecast incorporates an estimation of "natural conservation", namely, changes in end use efficiency over the study period that are projected to occur in the absence of new market interventions by Union.

Measure Total Resource Cost The Measure TRC calculates the net present value of natural gas, electricity and water savings that result from an investment in an efficiency technology or measure. The measure TRC is equal to its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy, water and equipment O&M costs. This calculation includes, among others, the following inputs: the avoided natural gas, electricity and water supply costs, the life of the technology, and the selected discount rate, which in this analysis has been set at 10%.

The Measure TRC test is the primary determinant of whether a measure is included in the economic potential.

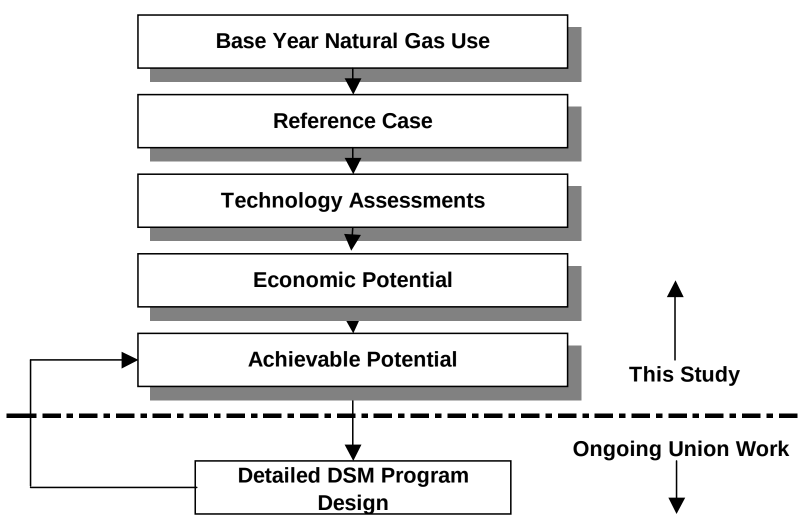
Economic Potential Forecast The Economic Potential Forecast is the level of natural consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost-effective from Union's perspective. All the energy efficiency technologies and measures that have a positive measure TRC are incorporated into the Economic Potential Forecast. These technologies and measures are applied at either natural stock turnover rates or at designated years for immediate application.

Achievable Potential The Achievable Potential is the proportion of the natural gas savings identified in the Economic Potential Forecast that could realistically be achieved within the study period. Achievable Potential recognizes that it is practically difficult to induce customers to purchase and install all the efficiency technologies that meet the criteria defined by the Economic Potential Forecast.

1.4 Approach

To meet the objectives outlined above, the study was conducted within an iterative process that involved a number of well-defined steps. At the completion of each step, the client reviewed the results and, as applicable, revisions were identified and incorporated into the interim results. The study then progressed to the next step. A summary of the steps is presented in Exhibit 1 and briefly discussed below.

Exhibit 1: Major Study Steps



Step 1: Develop Base Year Calibration Using Actual Union Sales Data

The Base Year (2007) is the starting point for the analysis. It provides a detailed description of "where" and "how" natural gas is currently used, based on actual natural gas sales.

The consultants compiled the best available data and used sector-specific macro models to estimate natural gas use; they then compared the results to Union's actual billing data to verify their accuracy.

Step 2: Develop Reference Case

The Reference Case uses the same sector-specific macro models to estimate the expected level of natural gas consumption that would occur over the study period with no new (post-2007) Union DSM initiatives. The Reference Case includes projected increases in natural gas consumption based on expected rates of population and economic growth; using the growth rates included in the Union 2007 load forecast for the period from 2007 to 2009, and the growth rates included in the Union 2010 load forecast for the period from 2010 to 2017. The Reference Case also makes an estimate for some “natural conservation”, that is, conservation that occurs even in the absence of new Union DSM programs. The Reference Case provides the point of comparison for the calculation of Technical, Economic and Achievable natural gas saving potentials.

Step 3: Assess DSM Technologies

The consultants researched a wide range of commercially available DSM technologies and practices that can enable Union’s customers to use natural gas more efficiently. In each case, the consultants assessed how much natural gas the DSM measures could save together with the expected cost, including purchase (capital), operating and maintenance costs.

For each DSM measure the consultants calculated the measure Total Resource Cost (TRC). The measure TRC calculates the net present value of changes to natural gas, electricity and water use that result from an investment in an efficiency technology or measure. The measure TRC is equal to its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy, water and equipment O&M costs. This calculation includes, among others, the following inputs: the changes in energy and water use, the supply costs of natural gas, electricity and water, the life of the technology, and the selected discount rate, which in this analysis has been set at 10%.

This approach allowed the consultants to compare a standardized cost for new technologies and measures with the cost of new natural gas supply, or other natural gas conserving measures, and to determine whether or not to include the DSM measure in the Economic Potential Forecast.

Step 4: Estimate Economic Natural Gas Savings Potential

The Economic Potential Forecast incorporates all “cost-effective” DSM measures reviewed in Step 3. To forecast the potential natural gas savings that are defined as economic, the consultants used the sector-specific macro models to calculate the level of natural gas consumption that would occur if Union’s customers installed all “cost-effective” technologies. “Cost effective” for the purposes of this study means that the measure has a positive measure TRC.

Step 5: Estimate Achievable Natural Gas Savings Potential

The Achievable Potential is the proportion of the savings identified in the Economic Potential Forecast that could realistically be achieved within the study period. Achievable Potential recognizes that it is difficult to induce customers to purchase and install all the energy efficiency technologies that meet the criteria defined by the Economic Potential forecast. The results are, therefore, presented within ranges. Consequently, the study assessed Achievable Potential under two differing scenarios[2]:

- **A Financially Unconstrained scenario**, in which potential is limited by market constraints but not by available DSM budgets.

- **A Static Marketing scenario**, in which potential is limited by DSM budgets on an individual technology[3] basis as well as by market constraints.

1.5 Study Organization and Reports

The 2008 study was organized and conducted by sector using a common methodology, as outlined above. That study was composed of a series of technical reports developed for Union Gas. They are:

- Natural Gas Energy Efficiency Potential, Residential Sector
- Natural Gas Energy Efficiency Potential, Commercial Sector
- Natural Gas Energy Efficiency Potential, Industrial Sector

As is noted in the "Note to Reader" section in each of the technical reports:

> "The primary economic data for this study was compiled during the period April to June of 2008. They represented the best available at the time. However, since that time, Canada and other global economies have entered a period of unprecedented economic uncertainty that may have significant impact on the results of this study, particularly in the short term."

The findings presented in this summary report vary from those presented in each of the technical reports, as they represent the results of the updated models. As was described in Section 1.1, the purpose of updating the models was to modify the assumptions and baseline data used in the initial 2008 Natural Gas Efficiency Potential Study to better reflect the impacts of economic changes.

1.5.1 This Report

The updated results of the individual sector reports are combined into this Summary Report, which is organized as follows:

- Section 2 presents the combined natural gas savings for the three sectors
- Section 3 presents a summary of the natural gas savings for the Residential sector
- Section 4 presents a summary of the natural gas savings for the Commercial sector
- Section 5 presents a summary of the natural gas savings for the Industrial sector

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[2] It should be emphasized that the estimation of Achievable Potential scenarios is not synonymous with program design or program targets. While closely linked to the discussion of Achievable Potential, program design and the setting of specific targets involve more detailed analysis that is beyond the scope of this study.

[3] It should be noted that the Static Marketing scenario results presented in this study are financially constrained at the level of an individual technology, not by a total DSM program budget. That step occurs at the point of detailed program design, which is beyond the scope of this study.

2 Summary of Study Findings

The study findings confirm that, despite the impacts of the economic recession, significant cost-effective natural gas DSM opportunities remain in the Residential, Commercial, and Industrial sectors within Union's service area.

2.1 Total Natural Gas savings Potential

Exhibit 2 and Exhibit 3 summarize the total combined natural gas savings for the Residential, Commercial, and Industrial sectors that have been identified in each of the individual sector technical reports. Highlights of the results for the total Union service area are shown in Exhibit 2. They include:

- In the Reference Case, total natural gas consumption for Union's service area decreases from approximately 10,457 million m^3/yr. in 2007 to about 10,284 million m^3/yr. by 2017, a decrease of about 1.7%.

- In the Economic Potential scenario, total natural gas consumption for Union's service area is estimated to reach 7,302 million m^3/yr. by 2012, and 7,270 million m^3/yr. by 2017. This represents a decrease in annual consumption of 2,814 million m^3/yr. by 2012 and 3,014 million m^3/yr. by 2017, relative to the Reference Case.[4]

- In the Financially Unconstrained Achievable Potential scenario, total natural gas consumption for Union's service area is estimated to reach 9,365 million m^3/yr. by 2012, and 8,885 million m^3/yr. by 2017. This represents a decrease in annual consumption of 752 million m^3/yr. by 2012 and 1,399 million m^3/yr. by 2017, relative to the Reference Case

- In the Static Achievable Potential scenario, total natural gas consumption for Union's service area is estimated to reach 9,698 million m^3/yr. by 2012, and 9,471 million m^3/yr. by 2017. This represents a decrease in annual consumption of 419 million m^3/yr. by 2012 and 813 million m^3/yr. by 2017, relative to the Reference Case

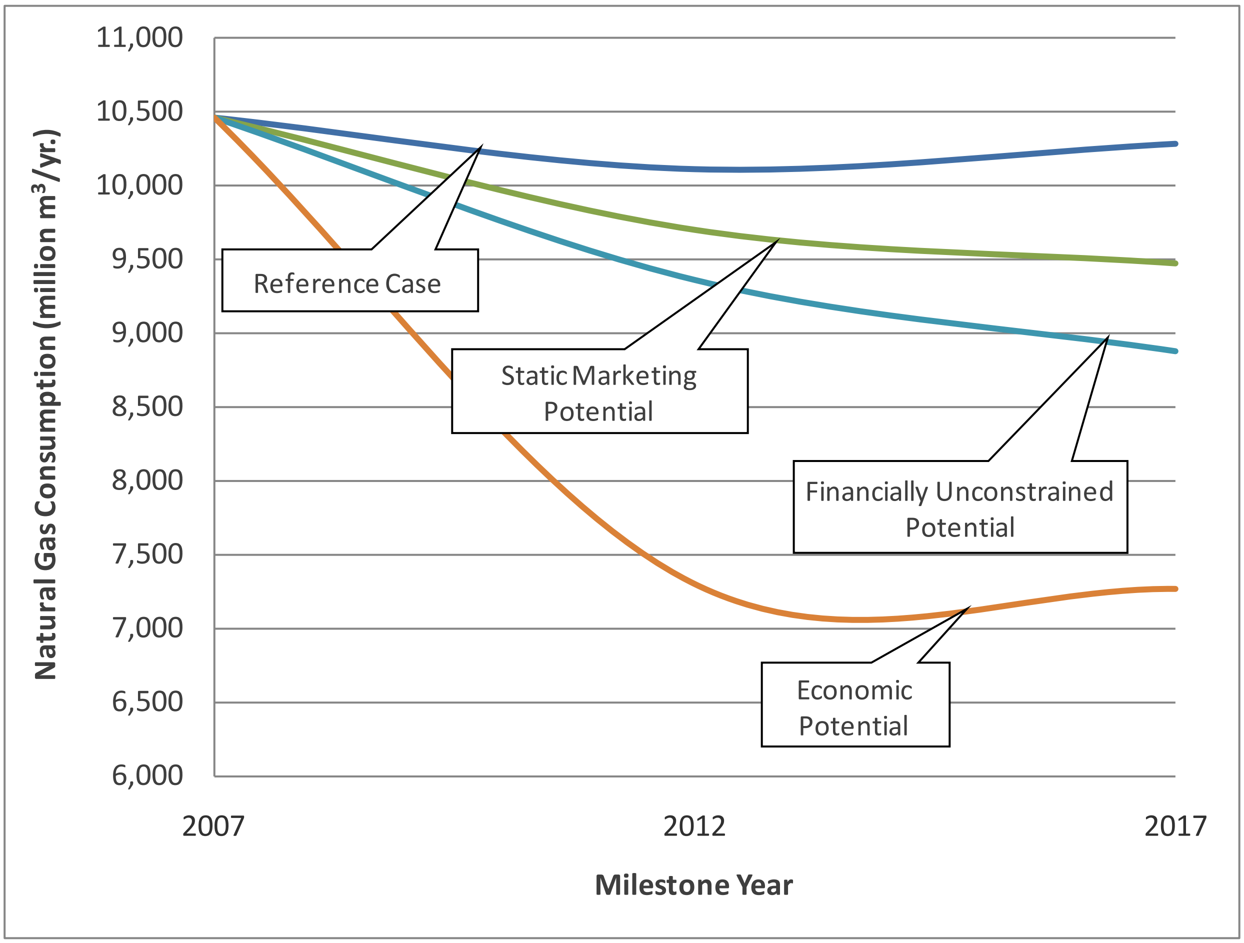
- If the Static Achievable Potential scenario natural gas savings for the total Union service area by 2017 are assessed from the perspective of average savings for the measures installed in each year, the approximate natural gas savings per year are 81.3 million m^3/yr. This compares with the 92.6 million m^3 of natural gas savings that were reported in Union's Demand Side Management 2009 Annual Report.

[4] The reported natural gas savings in each milestone year include the savings achieved by measures implemented in the years up to and including that milestone year, not just of the measures implemented in the reported milestone year. This means that although the savings reported occur in the milestone year alone, they are the result of several years of measure implementation.

Exhibit 2: Summary of Forecast Results for the Total Union Service Area, Annual Natural Gas Consumption and Savings, by Milestone Year and Forecast Scenario, 3 Sectors

Milestone Year	Annual Consumption, All 3 Sectors (million m^3/yr.)				Potential Annual Savings (million m^3/yr.)		
	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Financially Unconstrained	Static		Financially Unconstrained	Static
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2007	10,457						
2012	10,116	7,302	9,365	9,698	2,814	752	419
2017	10,284	7,270	8,885	9,471	3,014	1,399	813

Exhibit 3: Forecast Results for the Total Union Service Area, Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, 3 Sectors



2.2 Key Changes from 2008 Study

As part of the update process described in Section 1, ICF Marbek and Union Gas staff engaged in an iterative process to update the reference case. The 2017 achievable potential market penetration rates and their associated implementation curves were also updated. Updates were made for both the financially unconstrained and the static achievable potential scenarios. The exhibit below shows a comparison of the original and updated reference cases.

Exhibit 4: Summary of Changes to Natural Gas Consumption in the Reference Case, 3 Sectors

Milestone Year	Original Reference Case	Updated Reference Case	Difference
		million m^3/year	
2007	10,457	10,457	-
2012	10,520	10,116	- 404
2017	10,754	10,284	-470

The changes to the reference case, achievable participation rates, and adoption curves described above resulted in changes to savings in the static and financially unconstrained scenarios, as shown in Exhibit 5 and Exhibit 6, respectively.

Exhibit 5: Summary of Changes to Natural Gas Savings in the Static Achievable Potential Scenario, 3 Sectors

Milestone Year	Original Savings	Updated Savings	Difference
		thousand m^3/year	
2012	561,197	418,538	-142,660
2017	1,044,940	812,941	-231,999
% Savings relative to Reference Case, 2017	9.72%	7.91%	-2.26%

Exhibit 6: Summary of Changes to Natural Gas Savings in the Financially Unconstrained Achievable Potential Scenario, 3 Sectors

Milestone Year	Original Savings	Updated Savings	Difference
		thousand m^3/year	
2012	917,671	751,842	-165,828
2017	1,592,832	1,398,988	-193,843
% Savings relative to Reference Case, 2017	14.81%	13.60%	-1.88%

Compared to the original (2008) results, key differences in the updated study results include:

- The updates resulted in a lower reference case consumption and slightly lower potential savings in both the static and financially unconstrained scenarios.
- The scope of changes resulting from the updates vary by sector, with the greatest reduction in savings occurring in the commercial sector.

2.3 Key Observations

As illustrated in the preceding exhibits, despite a decade of successful DSM program implementation, there remains significant cost-effective DSM potential within Union's service area. This remaining opportunity reflects, in part, continued technology cost and performance improvements over the period. Key study observations are highlighted below.

2.3.1 Key Technologies and Measures

In the Residential sector, the measures that provide the most significant contribution to annual savings are technologies that reduce space heating requirements, such as high-performance windows, programmable thermostats, and air sealing in older homes.

In the Commercial sector, the most significant opportunities are actions that reduce space heating loads in existing buildings (e.g., building recommissioning, advanced building automation systems, space heating equipment upgrades and heat recovery), and actions that reduce hot water loads in existing buildings, including low-flow fixtures and water heating equipment upgrades. Building recommissioning is a particularly large opportunity.

In the Industrial sector, the most significant opportunities for natural gas savings are technologies that reduce gas usage for process heating, specifically ovens, dryers, kilns and furnaces. Implementation of energy-efficiency measures in boiler steam systems is also a significant opportunity. Measures that improve the total plant (referred to as system wide) energy efficiency are the third most significant opportunity area.

2.3.2 Markets and Trends

As the DSM market matures within Union's service area, niche or target markets are becoming increasingly important. Measures that may not pass the TRC test in a "typical" or "average" application often will pass in niche applications. Air sealing and insulation in older homes (built before 1980) is one example that was included in this study, as data was available.

Measures such as drain water heat recovery (DWHR) systems and DHW recirculation systems become more economically attractive as the number of household occupants increases. However, this group of measures were not included in the current results as suitable data was not available.

Market transformation approaches warrant additional consideration, particularly in the Residential and Commercial sectors. Alternately, opportunities such as those listed below suggest that the composition of the TRC calculation itself may need to be revisited to better consider non-energy benefits. For example:

- In the Residential sector, there remain significant untapped potential savings from technically mature measures that do not currently pass the TRC screen. The largest share of these additional potential savings is from air sealing and envelope insulation in existing homes. These measures do not pass the TRC screen as currently defined. However, they provide non-energy benefits such as increased comfort and reduced noise that are not currently captured in the TRC calculation. In addition, industry specialists emphasized that as insulation levels increase, proper air and moisture sealing is becoming increasingly essential to the long-term structural integrity of Ontario's housing stock. This situation presents both an opportunity and a possible technical issue that may be better addressed through a market transformation approach.

- In the Commercial sector, there remain significant untapped potential savings from technically mature measures that do not currently pass the TRC screen. The largest share of these additional potential savings are from air sealing and envelope upgrades, including wall insulation and more energy efficient glazing measures in existing buildings. These measures do not pass the TRC screen as currently defined. However, they provide non-energy benefits such as increased comfort and reduced noise that are not currently captured in the TRC calculation.

- In addition, industry specialists emphasized that some emerging technologies, such as solar preheated make-up air may be better addressed in a market transformation context. They provide “soft” benefits, such as visible contribution to corporate greening goals, which are not included in the TRC calculation.

3 Residential Sector

The Residential sector includes single-family detached homes, attached duplex, row and multi-family dwellings and apartments as well as a small number of other dwellings.

3.1 Approach

The detailed end-use analysis of energy efficiency opportunities in the Residential sector employed two linked modelling platforms: **HOT2000,** a commercially supported residential building energy-use simulation software; and **RSEEM** (Residential Sector Energy End-use Model), an ICF Marbek in-house spreadsheet-based macro model.

The major steps in the general approach to the study are outlined in Section 1.4 above (Approach). Specific procedures for the Residential sector were as follows:

- **Modelling of Base Year:** The consultants used the Union customer data to break down the Residential sector by four factors:
  - Type of dwelling (single detached, attached, apartment, etc.)
  - Heating category (natural gas or electric heat)
  - The age of the building
  - Service region.

To estimate the natural gas used for space heating, the consultants factored in building characteristics such as insulation levels, floor space and air tightness using a variety of data sources, including the Ontario EnerGuide for Houses database, Union billing data, local climate data and discussions with local contractors. They also used the results of Union customer surveys that provided data on type of heating system, number and age of household appliances, renovation activity, etc. Based on the available data sources, the consultants calculated an average natural gas use by end use for each dwelling type. The consultant's models produced a close match with actual Union sales data.

- **Reference Case Calculations:** For the Residential sector, the consultants developed profiles of new buildings for each type of dwelling. They estimated the growth in building stock using the same data as that contained in Union's most recent load forecast and estimated the amount of natural gas used by both the existing building stock and the projected new buildings and appliances. As with the Base Year calibration, the consultant's projection closely matches Union's own forecasts of future natural gas requirements.

- **Assessment of DSM Measures:** To estimate the economic and achievable energy savings potentials, the consultants assessed a wide range of commercially available energy efficiency measures and technologies such as:
  - Thermal upgrades to the walls, roofs and windows of existing buildings
  - More efficient space heating equipment and controls
  - More efficient water heating equipment and measures to reduce usage
  - Improved designs for new buildings
  - Addition of solar thermal technologies.

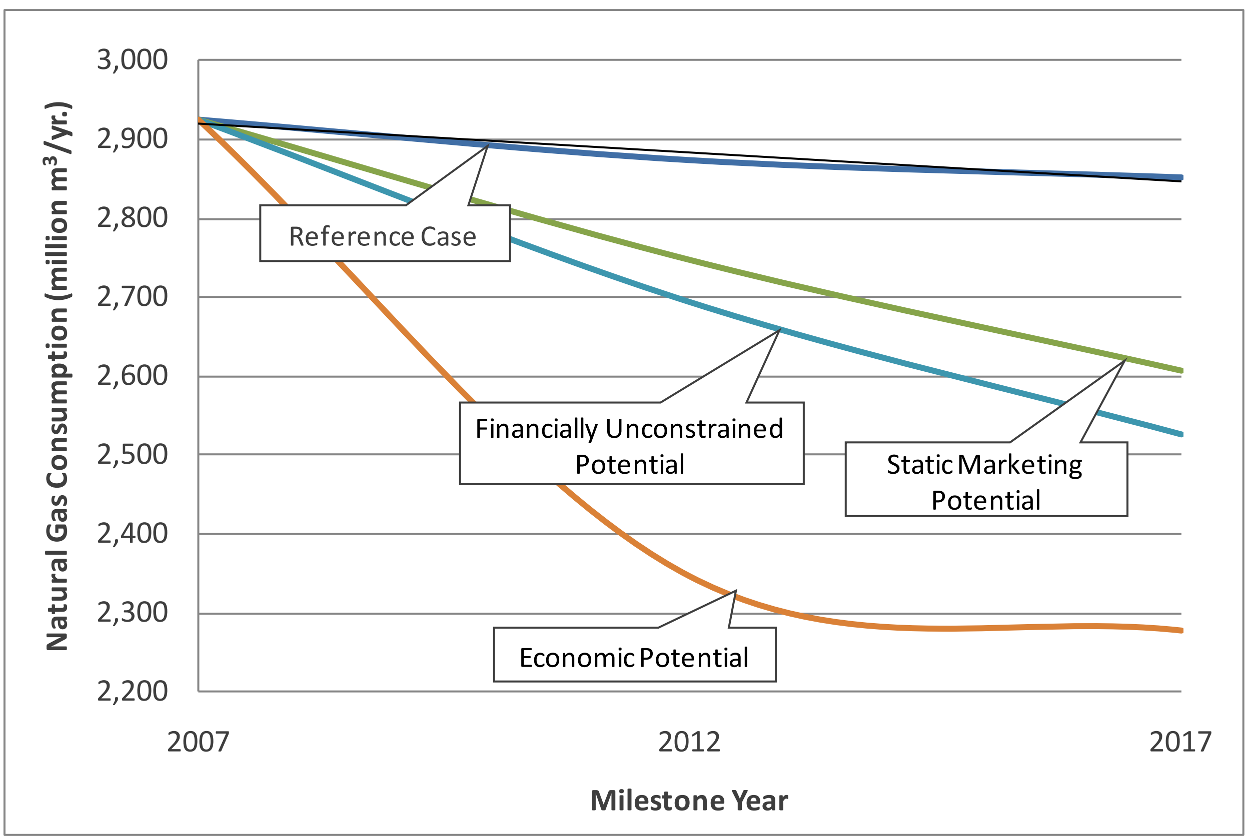
3.2 Residential Natural Gas Savings Potential

A summary of the levels of annual natural gas consumption and potential natural gas savings contained in each of the Residential sector forecasts addressed by the study is presented in Exhibit 7 and Exhibit 8, and is discussed briefly in the sub sections that follow.

Exhibit 7: Summary of Forecast Results for the Total Union Service Area, Annual Natural Gas Consumption and Savings, by Milestone Year and Forecast Scenario, Residential Sector

Milestone Year	Annual Consumption, Residential Sector (million m^3/yr.)				Potential Annual Savings (million m^3/yr.)		
	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Financially Unconstrained	Static		Financially Unconstrained	Static
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2007	2,925						
2012	2,873	2,347	2,693	2,747	526	179	126
2017	2,851	2,278	2,526	2,607	527	325	244

Exhibit 8: Graphic of Forecast Results for the Total Union Service Area, Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, Residential Sector



3.3 Base Year Natural Gas Use

In the Base Year of 2007, the residential sector in Union's total service area consumed about 2,925 million m^3 of natural gas. As illustrated in Exhibit 9, approximately 94% of this natural gas consumption occured in the single-family detached/duplex category of dwellings. The attached row housing/triplexes and quads category accounts for almost all the rest, with less than 0.1% consumed in mobile and other.

The Southern service region accounted for about 80% of the residential natural gas consumption in the Union Gas Service Area.

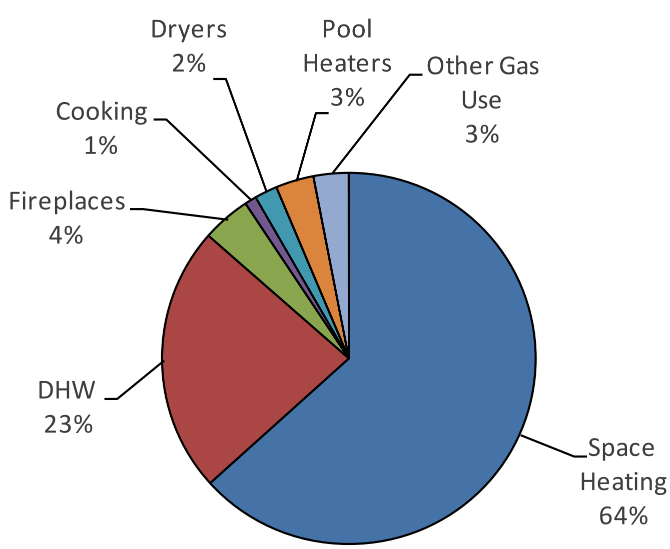
Exhibit 9: Base Year Residential Sector Natural Gas Use for the Total Union Service Area (1000 m^3/yr.)

Segment	Annual Consumption in Residential Sector (1000 m^3/yr.)							
	Space Heating	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use	Totals
Single-Family Detached/ Duplex	1,737,149	631,184	114,694	28,140	54,695	89,580	83,956	2,739,396
Attached/Row Housing/Tris & Quads	113,708	44,320	7,859	1,684	3,060	6,751	5,801	183,183
Other	1,433	397	74	13	26	51	54	2,048
TOTAL	1,852,289	675,900	122,627	29,837	57,781	96,382	89,810	2,924,627

Note: Any difference in totals is due to rounding.

As illustrated in Exhibit 10, space heating accounted for about 64% of total residential natural gas use. Domestic hot water (DHW) accounted for about 23% of the total natural gas use, followed by fireplaces (4%), and pool heaters (3%). Clothes dryers, cooking and selected other uses, such as barbeques and patio heaters, accounted for the remaining natural gas consumption.

Exhibit 10 Base Year Residential Sector Natural Gas Use for the Total Union Service Area, by End Use



3.4 Reference Case

In the absence of new DSM initiatives, the study estimates that natural gas consumption in the Residential sector will decrease from 2,925 million m^3/yr. in 2007 to about 2,851 million m^3/yr. by 2017. This represents an overall decrease of about 2.5% in the period and compares very closely with Union's own forecast, which also includes consideration of the impacts of "natural conservation".

Exhibit 11 shows the forecast levels of Residential sector natural gas consumption for the entire Union service area. The results are presented for each milestone year and end use.

Exhibit 11: Residential Sector Reference Case Natural Gas Use for the Total Union Service Area, by Dwelling Type, End Use and Milestone Year (1000 m^3/yr.)

Dwelling Type	Milestone Year	Gas Consumption (1000 m^3/yr.)							
		Total	Space Heating	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use
Single-Family Detached/ Duplex	2007	2,739,396	1,737,149	631,184	114,694	28,140	54,695	89,580	83,956
	2012	2,665,194	1,660,917	626,643	108,020	29,858	57,986	91,892	89,878
	2017	2,611,800	1,619,351	604,643	104,250	31,715	61,548	94,075	96,217
Attached/Row Housing/Tris & Quads	2007	183,183	113,708	44,320	7,859	1,684	3,060	6,751	5,801
	2012	205,475	122,578	52,185	8,704	2,164	3,926	8,393	7,526
	2017	236,766	136,659	61,859	10,226	2,790	5,057	10,412	9,764
Other	2007	2,048	1,433	397	74	13	26	51	54
	2012	1,997	1,379	396	70	14	28	53	58
	2017	1,969	1,358	384	67	15	29	54	62
TOTAL	2007	2,924,627	1,852,289	675,900	122,627	29,837	57,781	96,382	89,810
	2012	2,872,665	1,784,875	679,223	116,793	32,036	61,940	100,337	97,461
	2017	2,850,535	1,757,367	666,886	114,544	34,520	66,635	104,540	106,043

Note: Any difference in totals is due to rounding.

3.5 Economic Potential Forecast

Under the conditions of the Economic Potential Forecast[5], the study estimated that natural gas consumption in the Residential sector would decline to about 2,278 million m^3/yr. by 2017 for the total Union service area. Annual savings relative to the Reference Case are about 572 million m^3/yr. by 2017, or about 20%.

3.6 Achievable Potential

The Achievable Potential is the proportion of the economic natural gas savings (as noted above) that could realistically be achieved within the study period. In the Residential sector, the Achievable Potential for natural savings through technology adoption by 2017 was estimated to be 325 million m^3/yr. and 244 million m^3/yr., for the Financially Unconstrained and Static

[5] The level of natural gas consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost-effective. In this study, "cost-effective" means that the technology upgrade passes the measure Total Resource Cost (TRC) test, as discussed previously in Section 1.3.

Marketing scenarios, respectively. These savings represent about 57% and 43% of the savings identified in the Economic Potential Forecast.

The most significant opportunities for natural gas savings are technologies that reduce space heating requirements, such as high-performance windows, programmable thermostats, and air sealing in older homes.

3.7 Key Changes from 2008 Study

As part of the update process described in Section 1, ICF Marbek and Union Gas staff engaged in an iterative process to update the reference case to 2017. The 2017 achievable potential market penetration rates and their associated implementation curves were also updated. Updates were made for both the financially unconstrained and the static achievable potential scenarios. Exhibit 12 shows a comparison of the original and updated reference cases.

Exhibit 12: Summary of Changes to Natural Gas Consumption in the Reference Case, Total Residential Sector

Milestone Year	Original Reference Case	Updated Reference Case	Difference
	thousand m^3/year		
2007	2,924,627	2,924,627	0
2012	2,952,264	2,872,665	-79,599
2017	2,998,515	2,850,535	-147,980

The changes to the reference case, achievable participation rates and adoption curves described above, resulted in changes to savings in the static and financially unconstrained scenarios, as shown in Exhibit 10 and Exhibit 11, respectively.

Exhibit 13: Summary of Changes to Natural Gas Savings in the Static Achievable Potential Scenario, Total Residential Sector

Milestone Year	Original Savings	Updated Savings	Difference
	thousand m^3/year		
2012	131,012	125,679	-5,334
2017	261,401	243,739	-17,662
% Savings relative to Reference Case, 2017	8.7%	8.6%	-0.2%

Exhibit 14: Summary of Changes to Natural Gas Savings in the Financially Unconstrained Achievable Potential Scenario, Total Residential Sector

Milestone Year	Original Savings	Updated Savings	Difference
		thousand m^3/year	
2012	188,235	179,245	-8,989
2017	356,581	324,818	-31,763
% Savings relative to Reference Case, 2017	11.9%	11.4%	-0.5%

Compared to the original (2008) results, key differences in the updated study results include:

- In general, the updates resulted in a lower reference case consumption and a slightly lower potential savings in both the static and financially unconstrained scenarios.
- Updated savings are lower in the space heating and DHW end uses but slightly higher in the remaining end uses (i.e. fireplaces, dryers, and pool heaters).
- The reduction in savings potential is most significant in single-family detached homes in the Southern region.

3.8 Additional Observations

In addition to the preceding conclusions, two additional observations warrant note as they may affect future program strategies. They include:

- **Niche Markets Warrant Greater Program Focus:** As the DSM market matures within Union's service area, niche or target markets are becoming increasingly important. For example, measures that may not pass the TRC test in a "typical" or "average" application often will pass in niche applications. Air sealing and insulation in older homes (built before 1980) is one example that was included in this study, because the available data permitted an estimate of the higher heat loss in these older homes. Similarly, additional domestic hot water measures may be feasible in homes with a larger number of occupants. For example, drain water heat recovery systems and DHW recirculation systems become more economically attractive with larger household sizes. These latter measures have not been included in the current results as suitable data were not available.
- **Market Transformation Approaches Warrant Additional Consideration:** There remains additional untapped potential savings from technically mature measures that do not currently pass the TRC screen. The largest share of these additional potential savings is from air sealing and envelope insulation in existing homes. These measures do not pass the TRC screen as currently defined. However, they provide non-energy benefits such as increased comfort and reduced noise that are not currently captured in the TRC calculation. Similarly, industry specialists emphasized that as insulation levels increase, proper air and moisture sealing is becoming increasingly essential to the long-term structural integrity of Ontario's housing stock. This situation presents both an opportunity and a possible technical issue that may be better addressed through a market transformation approach.

4 Commercial Sector

The Commercial sector includes office and retail buildings, hotels and motels, restaurants, high-rise and mid-rise apartments, warehouses and a variety of small buildings. In this study, it also includes buildings that are often classified as "institutional," such as hospitals and nursing homes, schools and universities.

Throughout this report, use of the word "commercial" includes both commercial and institutional buildings unless otherwise noted.

4.1 Approach

The detailed end-use analysis of energy efficiency opportunities in the Commercial sector employed two linked modelling platforms: **CEEAM** (Commercial Energy and Emissions Analysis Model), an ICF Marbek in-house simulation model developed in conjunction with Natural Resources Canada (NRCan) for modelling natural gas use in commercial/institutional building stock, and **CSEEM** (Commercial Sector Energy End-use Model), an in-house spreadsheet-based macro model.

The major steps in the general approach to the study were outlined earlier in Section 1.4 (Approach). Specific procedures for the Commercial sector were as follows:

- **Modelling of Base Year:** ICF Marbek compiled data that defines "where" and "how" natural gas is currently used in existing commercial buildings. The consultants then created building energy use simulations for each type of commercial building and calibrated the models to reflect actual Union customer sales data. Estimated savings for the Other Commercial Buildings category were derived from the results of the modelled segments. They did not directly model that category because it is extremely diverse and the natural gas use of individual facility types is relatively small. The consultant's model produced a close match with actual Union sales data.

- **Reference Case Calculations:** For the Commercial sector, ICF Marbek developed detailed profiles of new buildings in each of the building segments, estimated the growth in building stock and estimated "natural" changes affecting natural gas consumption over the study period. As with the Base Year calibration, the consultant's projection closely matches Union's forecasts of future natural gas requirements.

- **Assessment of DSM Measures:** To estimate the economic and achievable natural gas savings potentials, the consultants assessed a wide range of commercially available DSM measures and technologies such as:
  - Measures to improve building envelope efficiency
  - Measures to reduce domestic hot water use, including solar hot water systems
  - Upgraded heating and ventilating systems
  - Improved construction in new buildings
  - Efficient cooking appliances.

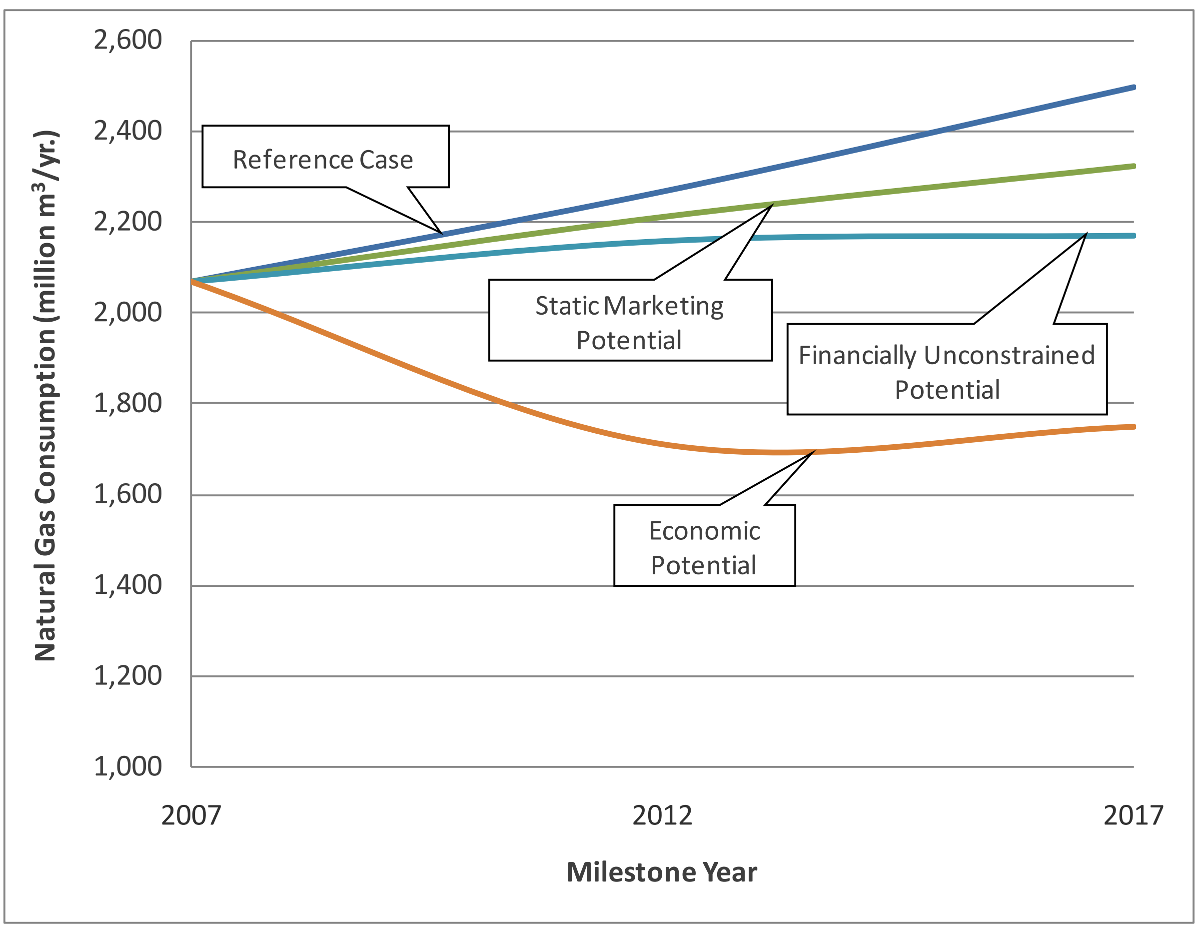
4.2 Commercial Natural Gas Savings Potential

A summary of the levels of annual natural gas consumption and potential natural gas savings contained in each of the Commercial sector forecasts addressed by the study is presented in Exhibit 15 and Exhibit 16, and is discussed briefly in the sub sections that follow.

Exhibit 15: Summary of Forecast Results for the Total Union Service Area Annual Natural Gas Consumption and Savings, by Milestone Year and Forecast Scenario, Commercial Sector

Milestone Year	Annual Consumption, Commercial Sector (million m^3/yr.)				Potential Annual Savings (million m^3/yr.)		
	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Financially Unconstrained	Static		Financially Unconstrained	Static
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2007	2,067						
2012	2,266	1,712	2,159	2,211	554	107	55
2017	2,496	1,750	2,171	2,323	746	325	173

Exhibit 16: Graphic of Forecast Results for the Total Union Service Area Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, Commercial Sector



4.3 Base Year Natural Gas Use

In the Base Year of 2007, the Commercial sector in Union's total service area consumed about 2,067 million m^3 of natural gas. The Southern service region accounted for approximately 77% of the total commercial sector sales shown in Exhibit 17, while the Northern service region accounted for the remaining 23%.

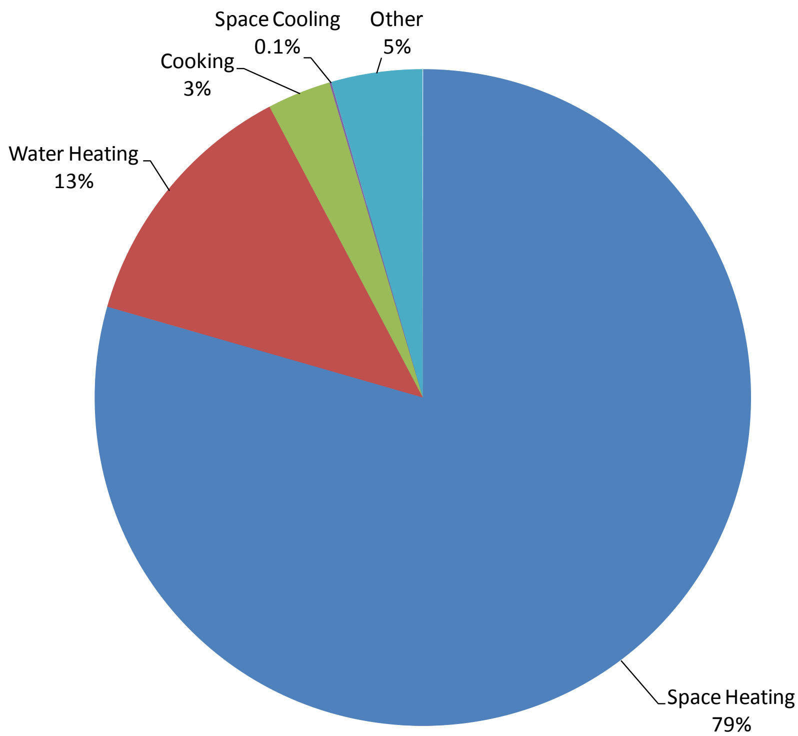
Among the modelled sub sectors shown in Exhibit 17, small offices, retail and high-rise apartments are the three largest natural gas users.

Exhibit 17: Base Year Commercial Sector Natural Gas Use for the Total Union Service Area ($1000\ m^3$/yr.)

Sub Sector	Natural Gas Consumption by End Use ($1000\ m^3$/yr.)					
	Space Heating	Water Heating	Cooking	Space Cooling	Other	Total
Large Office	99,744	7,774	324	185	11,716	119,743
Small Office	213,790	15,367	626	0	12,519	242,302
Retail	147,344	9,583	4,219	0	5,274	166,419
Large Hotel	7,649	4,766	643	0	919	13,978
Small Hotel/Motel	4,849	2,718	59	0	588	8,214
Contract Hospital	41,177	10,879	1,096	291	7,026	60,469
Hospital	18,650	3,762	489	70	1,361	24,332
Nursing Home	42,669	12,719	2,843	0	4,045	62,276
School	127,355	7,415	1,783	0	841	137,394
Contract University/College	58,582	10,173	2,868	617	7,170	79,409
University/College	12,355	1,837	444	118	846	15,600
Restaurant/Food Service	39,992	15,664	25,853	0	326	81,836
Warehouse	61,965	3,307	138	0	2,752	68,162
Contract Apartment	5,038	1,854	22	0	179	7,093
High-rise Apartment	120,369	40,913	522	0	4,176	165,980
Mid-rise Apartment	74,936	24,848	484	0	1,210	101,478
Other Buildings						391,810
Other Contract Institutional Buildings						320,568
Total	1,076,463	173,581	42,413	1,280	60,948	2,067,064

Exhibit 18 (overleaf) shows that space heating accounts for about 79% of total commercial sector natural gas use. Domestic hot water (DHW) accounts for about 13% of the total natural gas use, followed by cooking (3%). A variety of miscellaneous end uses account for the remaining natural gas consumption.

Exhibit 18: Base Year Commercial Sector Natural Gas Use for the Total Union Service Area, by End Use[6]



4.4 Reference Case

In the absence of new DSM initiatives, the study estimates that natural gas consumption in the Commercial sector will grow from 2,067 million m^3/yr. in 2007 to about 2,496 million m^3/yr. by 2017. This represents an overall increase of about 21% in the period and compares very closely with Union's own forecast, which also includes consideration of the impacts of "natural conservation".

Exhibit 19 (overleaf) shows the forecast levels of Commercial sector natural gas consumption for the entire Union service area. The results are presented for each milestone year and end use.

6 The pie chart in Exhibit 18 presents percentage of gas consumption by end use for modelled buildings only; the sub sectors "Other Commercial Buildings" and "Other" are included in the total load of Exhibit 4.1, but not included in the pie chart.

Exhibit 19: Commercial Sector Reference Case Natural Gas Use for the Total Union Service Area, by Building Type, End Use and Milestone Year (1000 m^3/yr.)

Sub Sector	Milestone Year	Total	Space Heating	Water Heating	Cooking	Space Cooling	Other
Large Office	2007	119,743	99,744	7,774	324	185	11,716
	2012	129,582	107,723	8,723	387	185	12,564
	2017	140,983	116,983	9,823	460	185	13,532
Small Office	2007	242,302	213,790	15,367	626	0	12,519
	2012	261,784	230,466	16,952	737	0	13,628
	2017	284,072	249,571	18,764	862	0	14,876
Retail	2007	166,419	147,344	9,583	4,219	0	5,274
	2012	183,110	161,262	10,912	4,860	0	6,075
	2017	202,740	177,668	12,470	5,601	0	7,001
Large Hotel	2007	13,978	7,649	4,766	643	0	919
	2012	15,329	8,261	5,305	726	0	1,037
	2017	16,881	8,968	5,925	819	0	1,170
Small Hotel/Motel	2007	8,214	4,849	2,718	59	0	588
	2012	8,990	5,263	3,024	66	0	637
	2017	9,880	5,738	3,375	74	0	692
Contract Hospital	2007	60,469	41,177	10,879	1,096	291	7,026
	2012	66,451	45,335	12,047	1,246	335	7,488
	2017	73,559	50,288	13,437	1,421	386	8,027
Hospital	2007	24,332	18,650	3,762	489	70	1,361
	2012	26,362	20,085	4,143	538	83	1,512
	2017	28,664	21,717	4,575	593	97	1,682
Nursing Home	2007	62,276	42,669	12,719	2,843	0	4,045
	2012	68,126	46,621	13,948	3,161	0	4,397
	2017	74,746	51,100	15,342	3,515	0	4,789
School	2007	137,394	127,355	7,415	1,783	0	841
	2012	149,769	138,209	8,571	2,030	0	958
	2017	164,205	150,885	9,914	2,314	0	1,092
Contract University/College	2007	79,409	58,582	10,173	2,868	617	7,170
	2012	87,596	65,294	11,035	3,120	617	7,530
	2017	96,885	72,913	12,018	3,403	617	7,934
University/College	2007	15,600	12,355	1,837	444	118	846
	2012	17,173	13,644	2,004	492	118	915
	2017	18,946	15,097	2,193	546	118	991
Restaurant/Food Service	2007	81,836	39,992	15,664	25,853	0	326
	2012	90,215	43,611	17,338	28,900	0	365
	2017	99,697	47,732	19,242	32,315	0	408
Warehouse	2007	68,162	61,965	3,307	138	0	2,752
	2012	75,226	68,253	3,695	156	0	3,121
	2017	83,384	75,523	4,143	177	0	3,541
Contract Apartment	2007	7,093	5,038	1,854	22	0	179
	2012	7,833	5,498	2,104	26	0	206
	2017	8,703	6,039	2,397	30	0	237
High-rise Apartment	2007	165,980	120,369	40,913	522	0	4,176
	2012	182,706	130,796	46,530	598	0	4,782
	2017	202,258	143,024	53,070	685	0	5,479
Mid-rise Apartment	2007	101,478	74,936	24,848	484	0	1,210
	2012	111,285	81,241	28,099	556	0	1,389
	2017	122,800	88,666	31,900	638	0	1,595
Other Buildings	2007	391,810					
	2012	430,942					
	2017	476,470					
Other Contract Institutional Buildings	2007	320,568					
	2012	353,226					
	2017	391,274					
Total	2007	2,067,064	1,076,463	173,581	42,413	1,280	60,948
	2012	2,265,704	1,171,562	194,431	47,600	1,337	66,605
	2017	2,496,147	1,281,914	218,587	53,453	1,403	73,046

4.5 Economic Potential Forecast

Under the conditions of the Economic Potential Forecast[7], the study estimated that natural gas consumption in the Commercial sector would decline to about 1,750 million m^3/yr. by 2017 for the total Union service area. Annual savings relative to the Reference Case would be about 746 million m^3/yr. by 2017, or about 30%.

4.6 Achievable Potential

The Achievable Potential is the proportion of the economic natural gas savings (as noted above) that could realistically be achieved within the study period. In the Commercial sector, the Achievable Potential for natural savings through technology adoption by 2017 was estimated to be 325 million m^3/yr. and 173 million m^3/yr., for the Financially Unconstrained and Static Marketing scenarios, respectively. These savings represent about 44% and 23% of the savings identified in the Economic Potential Forecast.

The most significant opportunities for natural gas savings are technologies that reduce space heating and water heating requirements.

4.7 Key Changes from 2008 Study

As part of the update process described in Section 1, ICF Marbek and Union Gas staff engaged in an iterative process to update the reference case to 2017. The 2017 achievable potential market penetration rates and their associated implementation curves were also updated. Updates were made for both the financially unconstrained and the static achievable potential scenarios. Exhibit 20 shows a comparison of the original and the updated reference cases.

Exhibit 20: Summary of Changes to Natural Gas Consumption in the Reference Case, Total Commercial Sector

Milestone Year	Original Reference Case	Updated Reference Case	Difference
	thousand m^3/year		
2007	2,067,064	2,067,064	0
2012	2,110,220	2,265,704	155,483
2017	2,157,072	2,496,147	339,075

The changes to the reference case, achievable participation rates and adoption curves described above, resulted in changes to savings in the static and financially unconstrained scenarios, as shown in Exhibit 21 and Exhibit 22, respectively.

7 The level of natural gas consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost-effective. In this study, "cost-effective" means that the technology upgrade passes the measure Total Resource Cost (TRC) test, as discussed previously in Section 1.4.

Exhibit 21: Summary of Changes to Natural Gas Savings in the Static Achievable Potential Scenario, Total Commercial Sector

Milestone Year	Original Savings	Updated Savings	Difference
		thousand m^3/year	
2012	112,609	55,170	-57,439
2017	259,202	172,704	-86,498
% Savings relative to Reference Case, 2017	10.4%	6.9%	-3.5%

Exhibit 22: Summary of Changes to Natural Gas Savings in the Financially Unconstrained Achievable Potential Scenario, Total Commercial Sector

Milestone Year	Original Savings	Updated Savings	Difference
		thousand m^3/year	
2012	172,330	107,180	-65,150
2017	390,076	325,301	-64,775
% Savings relative to Reference Case, 2017	15.6%	13.0%	-2.6%

Compared to the original (2008) results, key differences in the updated study results include:

- In general, updates result in a higher reference case consumption and lower potential savings in both the static and financially unconstrained scenarios.
- In absolute terms, updated savings are lower for all end uses and sub sectors.
- In relative terms, space heating savings make up a smaller share of overall savings in both achievable scenarios. Conversely, water heating savings account for a larger relative share in both achievable scenarios.
- As a consequence of the above, sub sectors with high water heating natural gas use, such as hotels, hospitals, restaurants and apartments make up a larger share of overall savings in both achievable scenarios.

4.8 Additional Observations

In addition to the preceding conclusions, three additional observations warrant note as they may affect future program strategies. They include:

- **Rate of measure implementation has a large effect on overall savings:** For measures that pass the TRC screen on an incremental cost basis, low participation rates in early milestone years create a significant "lost opportunity." This is particularly relevant to the replacement of equipment with a very long life (i.e. space heating equipment), building renovations such as envelope improvements, and new building construction. The gap between Economic Potential and Achievable Potential savings presented in this study is due in large part to this significant lost opportunity that occurs in early milestone years.

- **Savings arising from full cost measures may be delayed without eroding overall potential:** This is a corollary of the above point, and most pertinent to the discussion of the largest opportunity identified in this study, recommissioning. As recommissioning passes the TRC screen at full cost, eligible buildings that are not recommissioned remain as future opportunities, while incremental cost opportunities that are not exploited represent lost opportunities. This may be especially relevant to programming strategy during periods of economic downturn, when building owners and managers may be less likely to implement measures despite an attractive payback.

- **Market transformation approaches warrant additional consideration:** There remains an additional untapped potential savings from technically mature measures that do not currently pass the TRC screen. The largest share of these additional potential savings are from air sealing and envelope upgrades, including wall insulation and more energy efficient glazing measures in existing buildings. These measures do not pass the TRC screen as currently defined. However, they provide non-energy benefits such as increased comfort and reduced noise that are not currently captured in the TRC calculation. In addition, industry specialists emphasized that some emerging technologies, such as solar preheated make-up air, may be better addressed in a market transformation context. They provide “soft” benefits, such as visible contribution to corporate greening goals, which are not included in the TRC calculation.

5 Industrial Sector

The Industrial sector consists of the eight largest natural gas consuming industrial sub sectors within the Union service area plus an additional miscellaneous category that combines the remaining smaller industry groups. As applicable, each of the eight large industrial sub sectors was further divided into the very large “Contract” customers and the remaining “Other” sites. The large Contract customers, which are the primary focus of this study, are: Primary Metal, Chemical, Paper, Transportation and Machinery, Petroleum Refineries, Mining, Food and Beverage and Non-metallic Mineral.

5.1 Approach

The detailed end-use analysis of energy efficiency opportunities in the Industrial sector employed ICF Marbek’s customized macro model. The model is organized by major industrial sub sector and major end use.

Natural gas end-use profiles were developed for the nine sub sectors described above. The profiles map proportionally how much natural gas is used by each of the end uses for each sub sector. These profiles represent the sub sector archetypes and are used in the model to calculate the natural gas used by each end use for each sub sector.

The major steps in the general approach to the study are outlined in Section 1.4 above (Approach). Specific procedures for the Industrial sector were as follows:

- **Modelling of Base Year:** The consultants compiled Base Year data on the industrial sector from a variety of sources, including Union’s customer information, the study team’s own energy assessment experience within many of the sub sectors and secondary data sources. The macro model results produced a close match with actual Union sales data.

- **Reference Case Calculations:** The consultants prepared a Reference Case forecast based on projected growth forecasts provided by Union, which includes anticipated closing of existing facilities and opening of new facilities.

- **Assessment of DSM Measures:** To estimate the economic and achievable natural gas savings potentials, the consultants assessed a wide range of commercially available energy efficiency measures and technologies such as:

  - Integrated control systems
  - More efficient boiler, steam and hot water systems
  - Efficient process heating technologies
  - Efficient space heating and ventilation, including solar thermal technologies.

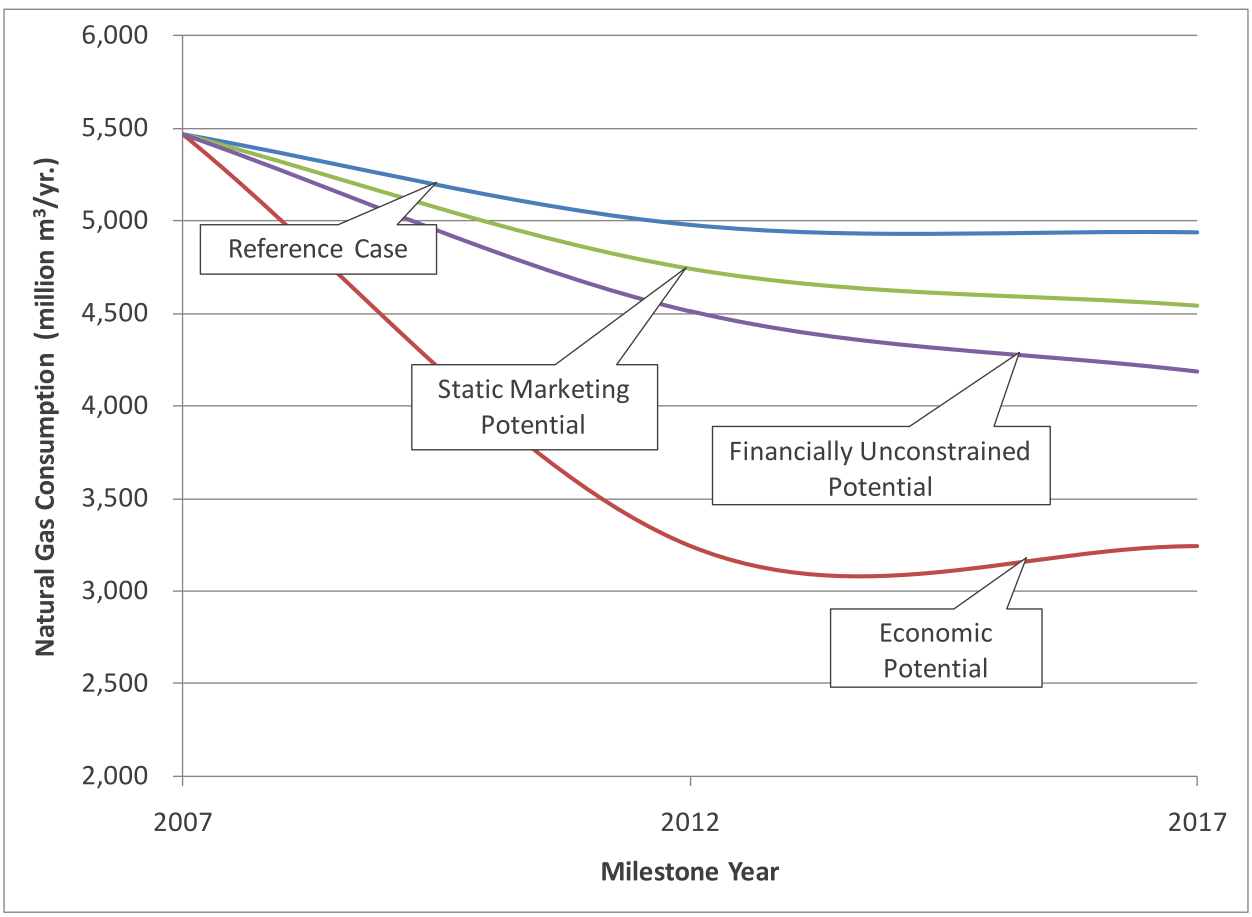
5.2 Industrial Natural Gas Savings Potential

A summary of the levels of annual natural gas consumption and potential natural gas savings contained in each of the Industrial sector forecasts addressed by the study is presented in Exhibit 23 and Exhibit 24, and is discussed briefly in the sub sections that follow.

Exhibit 23: Summary of Forecast Results for the Total Union Service Area Annual Natural Gas Consumption and Savings, by Milestone Year and Forecast Scenario, Industrial Sector

Milestone Year	Annual Consumption, Industrial Sector (million m^3/yr.)				Potential Annual Savings (million m^3/yr.)		
	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Financially Unconstrained	Static		Financially Unconstrained	Static
2007	5,465						
2012	4,978	3,244	4,513	4,740	1,734	465	238
2017	4,937	3,242	4,189	4,541	1,695	749	396

Exhibit 24: Graphic of Forecast Results for the Total Union Service Area Annual Natural Gas Consumption and Savings by Milestone Year and Forecast Scenario, Industrial Sector



5.3 Base Year Natural Gas Use

In the Base Year of 2007, the Industrial sector in Union's total service area consumed about 5,465 million m^3 of natural gas. This volume excludes natural gas used for power generation, co-generation and industrial feedstock, as these uses of natural gas are beyond the scope of this study.

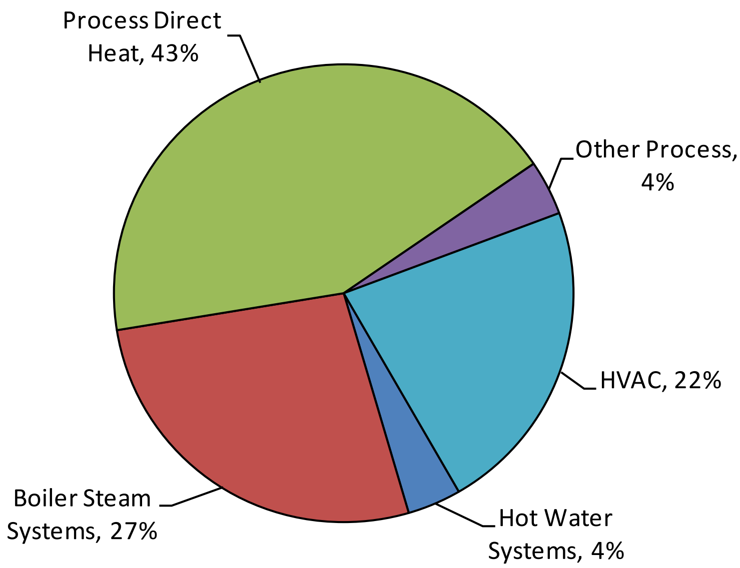
The twelve core industrial sub sectors (both contract and other customers), shown in Exhibit 25, account for 88% of the total industrial natural gas consumption. About 70% of the total industrial natural gas consumption occurs in the Southern service region.

Exhibit 25: Base Year Industrial Sector Natural Gas Consumption for the Total Union Service Area (1,000 m^3/yr.)

Sub Sector	End Use					Total	
	Hot Water Systems	Boiler Steam Systems	Process Direct Heat	Other Process	HVAC		
Contract Primary Metal	27,568	161,964	963,099	31,428	194,357	1,378,415	25%
Contract Chemical	20,117	408,369	331,925	74,222	171,201	1,005,834	18%
Other Chemical	741	15,034	12,220	2,732	6,303	37,030	0.7%
Contract Paper	11,344	353,887	107,431	10,380	84,175	567,218	10%
Contract Transportation and Machinery	7,827	91,046	117,313	15,868	159,278	391,332	7%
Other Transportation and Machinery	2,984	34,718	44,734	6,051	60,736	149,223	3%
Contract Petroleum Refineries	7,520	72,251	253,607	6,738	35,873	375,989	7%
Contract Mining	64,023	80,029	112,041	16,006	48,017	320,117	6%
Other Mining	4.9	6.1	8.6	1.2	3.7	25	0.0004%
Contract Food and Beverage	20,142	120,397	69,212	15,585	26,436	251,771	5%
Other Food and Beverage	4,463	26,680	15,337	3,454	5,858	55,793	1%
Contract Non-Metallic Mineral	5,598	33,477	198,345	10,581	31,910	279,911	5%
Miscellaneous Industrial	33,945	75,984	127,031	17,690	398,131	652,781	12%
Total	206,277	1,473,842	2,352,303	210,736	1,222,280	5,465,438	
%	4%	27%	43%	4%	22%		

As illustrated in Exhibit 26, process direct heat accounts for about 43% of total industrial sector natural gas use in the base year. Boiler steam systems account for about 27% of the total natural gas use, followed by heating, ventilation and air conditioning (HVAC), which accounts for about 22%. Other processes and hot water systems account for the remaining natural gas consumption.

Exhibit 26: Base Year Industrial Sector Natural Gas Use for the Total Union Service Area, by End Use



5.4 Reference Case

In the absence of new DSM initiatives, the study estimates that natural gas consumption in the Industrial sector will decrease from 5,465 million m^3/yr. in 2007 to about 4,937 million m^3/yr. by 2017. This represents an overall decrease of about 9.7% in the period and compares very closely with Union's own forecast, which also includes consideration of the impacts of "natural conservation".

Exhibit 27 shows the forecast levels of Industrial sector natural gas consumption for the Union service area. The results are presented for each milestone year, service region and sub sector.

Exhibit 27: Industrial Sector Reference Case Natural Gas Use for the Total Union Service Area, by Sub Sector and Milestone Year (1000 m^3/yr.)

Sub Sector	Northern Region			Southern Region			All Regions		
	2007	2012	2017	2007	2012	2017	2007	2012	2017
Contract Primary Metal	398,032	461,065	467,735	980,383	1,011,357	1,010,852	1,378,415	1,472,422	1,478,587
Contract Chemical	256,247	214,125	211,763	749,587	675,774	621,166	1,005,834	889,900	832,929
Other Chemical	2,310	1,930	1,909	34,720	31,301	28,772	37,030	33,231	30,681
Contract Paper	537,762	202,027	179,666	29,456	28,632	28,632	567,218	230,660	208,298
Contract Transportation and Machinery	10,593	10,582	10,582	380,739	181,276	181,276	391,332	191,858	191,858
Other Transportation and Machinery	1,411	1,410	1,410	147,811	70,375	70,375	149,223	71,785	71,785
Contract Petroleum Refineries	-	-	-	375,989	587,605	587,605	375,989	587,605	587,605
Contract Mining	307,752	229,235	223,060	12,365	11,791	11,791	320,117	241,026	234,851
Other Mining	-	-	-	25	23	23	25	23	23
Contract Food and Beverage	39,603	74,402	75,460	212,168	240,232	241,044	251,771	314,634	316,504
Other Food and Beverage	2,527	4,747	4,815	53,266	60,311	60,515	55,793	65,058	65,330
Contract Non-Metallic Mineral	21,239	20,799	20,799	258,672	97,129	97,129	279,911	117,928	117,928
Miscellaneous Industrial	76,363	37,532	37,532	576,418	724,392	763,575	652,781	761,924	801,107
Total	1,653,839	1,257,855	1,234,730	3,811,599	3,720,200	3,702,756	5,465,438	4,978,056	4,937,486

5.5 Economic Potential Forecast

Under the conditions of the Economic Potential Forecast[8], the study estimated that natural gas consumption in the Industrial sector would decline to about 3,242 million m^3/yr. by 2017 for the total Union service area. Annual savings relative to the Reference Case are about 1,695 m^3/yr. by 2017, or about 34%.

5.6 Achievable Potential

The Achievable Potential is the proportion of the economic natural gas savings (as noted above) that could realistically be achieved within the study period. In the Industrial sector, the Achievable Potential for natural savings through technology adoption by 2017 was estimated to be 749 million m^3/yr. and 396 million m^3/yr., for the Financially Unconstrained and Static Marketing scenarios, respectively. These savings represent about 44% and 23% of the savings identified in the Economic Potential Forecast.

5.7 Key Changes from 2008 Study

As part of the update process described in Section 1, ICF Marbek and Union Gas staff engaged in an iterative process to update the reference case to 2017. The 2017 achievable potential market penetration rates and their associated implementation curves were also updated. Updates were made for both the financially unconstrained and the static achievable potential scenarios. Exhibit 28 shows a comparison of the original and updated reference cases.

Exhibit 28: Summary of Changes to Natural Gas Consumption in the Reference Case, Total Residential Sector

Milestone Year	Original Reference Case	Updated Reference Case	Difference
	million m^3/year		
2007	5,465	5,465	-
2012	5,458	4,978	-480
2017	5,598	4,937	-661

The changes to the reference case, achievable participation rates, and adoption curves described above resulted in changes to savings in the static and financially unconstrained scenarios, as shown in Exhibit 29 and Exhibit 30, respectively.

[8] The level of natural gas consumption that would occur if all equipment was upgraded to the level that is cost-effective. In this study, "cost-effective" means that the technology upgrade passes the measure Total Resource Cost (TRC) test, as discussed previously in Section 1.3.

Exhibit 29: Summary of Changes to Natural Gas Savings in the Static Achievable Potential Scenario, Total Industrial Sector

Milestone Year	Original Savings	Updated Savings	Difference
		thousand m^3/year	
2012	317,576	237,689	-79,887
2017	524,337	396,498	-127,839
% Savings relative to Reference Case, 2017	9.4%	8.0%	-1.3%

Exhibit 30: Summary of Changes to Natural Gas Savings in the Financially Unconstrained Achievable Potential Scenario, Total Industrial Sector

Milestone Year	Original Savings	Updated Savings	Difference
		thousand m^3/year	
2012	557,106	465,417	-91,689
2017	846,175	748,869	-97,305
% Savings relative to Reference Case, 2017	15.1%	15.2%	0.05%

Compared to the original (2008) results, key differences in the updated study results include:

- The updates resulted in a lower reference case consumption and slightly lower potential savings in both the static and financially unconstrained scenarios.
- Updated savings are lower in all end uses, but the reduction is greatest in the Boiler Steam System and Other Process end uses.
- Updated savings are lower in all sub sectors, except the Contract Petroleum Refineries, Contract Food and Beverage, Other Food and Beverage, and Miscellaneous Industrial sub sectors. The greatest decrease in savings occurs in the Contract Non-Metallic Mineral sub sector.

5.8 Additional Observations

In addition to the preceding conclusions, three additional observations warrant note as they may affect future program strategies. They include:

- ***Rate of measure implementation has a large effect on overall savings.*** For measures that pass the TRC screen on an incremental cost basis, low participation rates in early milestone years create a significant "lost opportunity." This is particularly relevant to the replacement of equipment with a very long life, which is applicable to most industrial technologies and measures. The gap between Economic Potential and Achievable Potential savings presented in this study is due in large part to this significant lost opportunity that occurs in early milestone years.

- ***Bundling of measures to develop program concepts has an impact on the achievable potential results.*** To model the achievable potential scenario measures were grouped into bundles that were manageable within the scope and budget of the project. The results provide an indication of savings potential based on the specific set of measures included in the bundles. In defining specific programs it will be important to interpret the Achievable Potential savings potential by assessing individual measures within the context of the Economic Potential and the measure TRC results.

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Project ID: 114103

Natural Gas
Energy Efficiency Potential

Residential Sector

–Final Report–

Submitted to:

Union Gas

Submitted by:

Marbek Resource Consultants Ltd.

March 18, 2009

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Note to Reader

The primary economic data for this study was compiled during the period April to June of 2008. They represented the best available at the time. However, since that time, Canada and other global economies have entered a period of unprecedented economic uncertainty that may have significant impact on the results of this study, particularly in the short term. Three elements that affect this study's results are particularly impacted by these economic changes:

- Sector growth rates
- DSM Program participation rates that are used to determine the estimates of achievable potential
- Type of DSM investment

Sector Growth Rates

Key factors underlying Union's industrial load forecast and the study's Reference Case such as gross domestic product (GDP), energy prices, commodity prices, currency values etc. are expected to change under the current conditions. The impact of these changes, at least in the short term, is expected to be reduced industrial output accompanied by reduced consumption of natural gas. At this time, it is impossible to predict either the extent or the duration of the economic downturn and its consequent impact on natural gas consumption.

DSM Program Participation Rates

The participation rates estimated during the Achievable Potential workshops do not explicitly take into account changes in industry outlook as a result of the economic downturn. In the short term, the expected impact would be lower discretionary investment and, hence, lower program participation rates than those presented in this report. As neither the extent nor the duration of the economic downturn is known at this time, it is not possible to estimate the total reduction in program participation rates over the full study period.

Type of DSM Investment

Many of the DSM investments included in this study's results pass the economic screen on a full cost basis and can be implemented at any time over the study period. This means that even if program participation rates are reduced in the short term, there remains the possibility of recapturing some of these opportunities in later portions of the study period. However, some of the DSM investment opportunities included in the study's results occur only when existing equipment is replaced at the end of its life. This means that if program participation rates are reduced in the short term, then the opportunity to implement the energy efficient model is lost until the equipment again comes up for replacement, which in most applications will be beyond the period covered by this study.

EXECUTIVE SUMMARY

❑ Background and Objectives

Union Gas Ltd. (Union) is a natural gas utility serving almost 1.3 million customers in the residential, commercial and industrial markets. Union is a regulated utility with a franchise area spread across the Province of Ontario, including northern, southwestern and southeastern cities and towns. Union distributes approximately 13.9 billion m^3 (489.9 billion ft^3) of natural gas to its customers annually.

Since 1997, Union has delivered demand side management (DSM) programs to its customers under a mandate from the provincial regulator, the Ontario Energy Board (OEB). Union offers DSM programs to all in-franchise customer rate classes and across all sectors and the DSM savings target and budget are determined through a rate proceeding with the OEB. Over the past eleven years Union has delivered approximately 614 million m^3 of natural gas savings and over $1 billion in net Total Resource Cost (TRC) benefits.

Union has been participating in a market of increasing DSM program maturity. This market is continually evolving in its engagement with energy efficiency through growing voluntary initiatives and more stringent codes and standards. In addition, changes in the economy have started to show signs of negatively impacting the commercial and industrial marketplace in Union's Service Area.

In the DSM Generic Proceeding held in 2006, Union committed to creating an updated Market Potential Study for input into the next DSM plan. This study will support the identification of potential energy savings for Union's next multi-year plan and be part of Union's regulatory filing in the next DSM rate case.

Union has initiated this current study within the context of the conditions noted above. When completed, the results of this natural gas Efficiency Potential Study will provide a foundation that Union can use to guide the development of its longer-term DSM strategy, including new measures and targets.

In the DSM Generic Proceeding held in 2006, Union committed to creating an updated Market Potential Study for input into the next DSM plan. Union has initiated this current study within the context of the conditions noted above. When completed, the results of this Natural Gas Efficiency Potential Study will provide a foundation that Union can use to guide the development of its longer-term DSM strategy, including new measures and targets. More specifically, this includes support for Union's filing to the OEB regulatory application for the next multi-year DSM plan by:

- Estimating the achievable and economic potential for DSM measures across all applicable technologies, markets and sectors in Union's franchise area
- Giving shape to, and refining ongoing energy-efficiency work by Union in order to develop its next multi-year DSM plan, and
- Provide information that is actionable and can be easily converted to plan and program development.

- Scope and Organization

This study covers a 10-year study period from 2007 to 2017 and addresses the Residential, Commercial and Industrial sectors. The 2007 calendar year was selected as the Base Year as this is the most recent year for which complete customer data are available.

The study addresses the full range of natural gas efficiency measures. Results are presented for the total Union Service Area and for two service regions: Southern and Northern. The study results are disaggregated by service region due to differences in building stock and weather conditions (heating degree days).

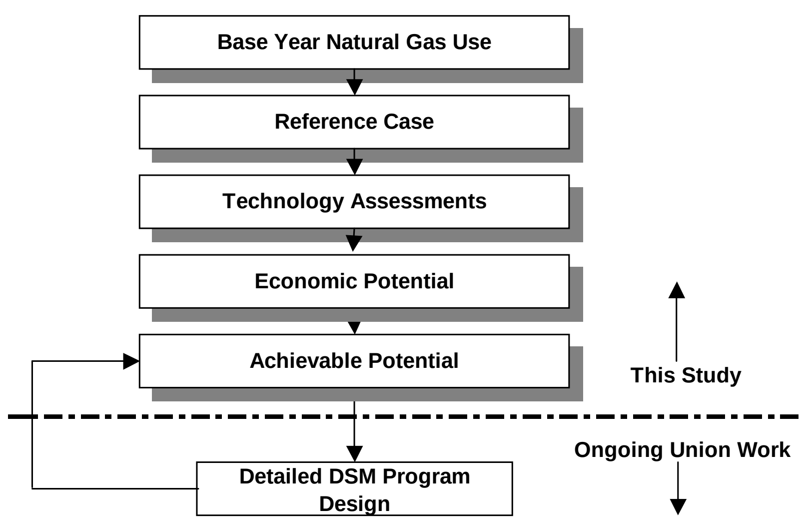
This report presents the results for Union's Residential sector.

- Approach

The detailed end-use analysis of energy-efficiency opportunities in the Residential sector employed two linked modelling platforms: **HOT2000,** a commercially supported residential building energy-use simulation software, and **RSEEM** (Residential Sector Energy End-use Model), a Marbek in-house spreadsheet-based macro model. The models are described in further detail in Section 1.

The major steps involved in the analysis are shown in Exhibit ES1 and are discussed in greater detail in Section 1. As illustrated in Exhibit ES1, the results of this study, and in particular the estimation of Achievable Potential,[1] support Union's on-going DSM program planning; however, it should be emphasized that the estimation of Achievable Potential is not synonymous with either the setting of specific targets or with detailed program design, which are beyond the scope of this study.

Exhibit ES1: Study Approach - Major Analytical Steps



[1] The proportion of savings identified that could realistically be achieved within the study period, under various program spending and market conditions.

- ❑ Overall Study Findings

As in any study of this type, the results presented in this report are based on a large number of important assumptions. Assumptions such as those related to the current penetration of energy-efficient technologies, the rate of future growth in the province's building stock and customer willingness to implement new efficiency measures are particularly influential. Wherever possible, the assumptions used in this study are consistent with those used by Union and are based on best available information, which in many cases includes the professional judgement of the consultant team, Union personnel and local experts. The reader should, therefore, use the results presented in this report as best available estimates; major assumptions, information sources and caveats are noted throughout.

The study findings confirm the existence of significant cost-effective DSM potential in Union's Residential sector. Savings estimates were based on two marketing scenarios: the Financially Unconstrained marketing scenario assumes both an aggressive program approach and a very supportive context (e.g., healthy economy, very strong public commitment to climate change mitigation, etc.) while the Static Marketing scenario assumes that market interest and customer commitment to energy efficiency and sustainable environmental practices remain approximately as current. Similarly, federal, provincial and municipal government energy-efficiency and GHG mitigation efforts remain similar to the present.

It was found that natural gas savings from efficiency improvements within the Union Service Area would provide between 357 and 261 million m^3/year of natural gas savings by 2017 in, respectively, the Financially Unconstrained and the Static Marketing Achievable scenarios. The most significant Achievable Savings opportunities were in the actions that reduce space heating loads in existing dwellings (e.g., high-performance windows, programmable thermostats and air sealing and insulation in older homes).

Although program costs for the Financially Unconstrained and the Static Marketing scenarios will vary depending on the specific composition of the future program portfolio, both scenarios show an evident trend towards higher future costs to achieve natural gas savings and TRC benefits.[2] This trend recognizes that savings from DSM programs tend to become more expensive over time, as the most attractive measures gain greater market penetration and only the more challenging and expensive measures remain.[3] However, to counteract this trend, it is also expected that some relatively new technologies, such as tankless water heaters and high-performance windows, may become less expensive as they gain greater sales volumes. These technologies would then become more financially attractive from a DSM program perspective.

[2] Design of a DSM program portfolio is beyond the scope of this current study.

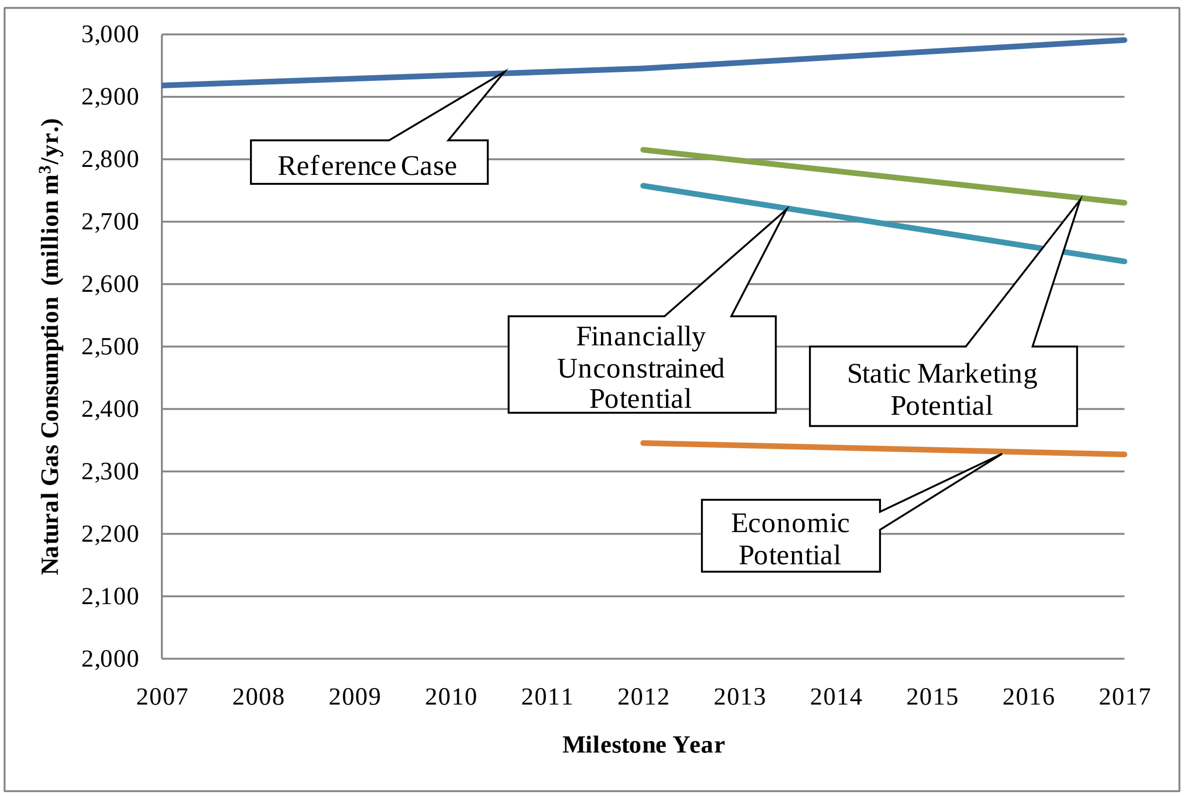
- Summary of Natural Gas Savings

A summary of the levels of annual natural gas consumption contained in each of the forecasts addressed by the study is presented in Exhibits ES2 and ES3, by milestone year, and discussed briefly in the paragraphs below.

Exhibit ES2: Summary of Forecast Results for the Total Union Service Area – Annual Natural Gas Consumption and Savings, Residential Sector (million m³/yr.)

Annual Consumption in Residential Sector (million m³)					Potential Annual Savings (million m³/yr.)		
Milestone Year	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Financially Unconstrained	Static		Financially Unconstrained	Static
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2007	2,925						
2012	2,952	2,350	2,764	2,821	602	188	131
2017	2,999	2,332	2,642	2,737	666	357	261

Exhibit ES3: Graphic of Forecast Results for the Total Union Service Area – Annual Natural Gas Consumption, Residential Sector (million m³/yr.)



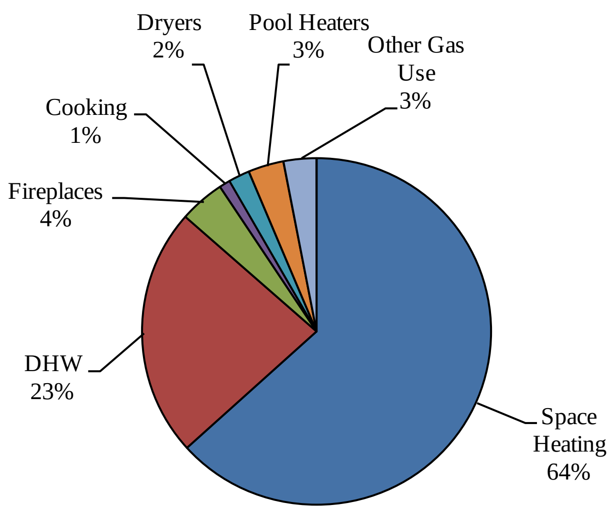
Base Year Natural Gas Use

In the Base Year of 2007, Union's Residential sector consumed about 2,925 million m^3 of natural gas. Exhibit ES4 depicts graphically the end use applications that make up this consumption.

Exhibit ES4: Base Year Natural Gas Use by End Use for the Total Union Service Area, Residential Sector

Segment	Space Heating	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use	Totals
	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.
Single-Family Detached/ Duplex	1,737,149	631,184	114,694	28,140	54,695	89,580	83,956	2,739,396
Attached/Row Housing/Tris & Quads	113,708	44,320	7,859	1,684	3,060	6,751	5,801	183,183
Other	1,433	397	74	13	26	51	54	2,048
TOTAL	1,852,289	675,900	122,627	29,837	57,781	96,382	89,810	2,924,627

Note: Any difference in totals is due to rounding.



Union's residential customers primarily reside in single family dwellings. As a result, nearly 94% of the natural gas consumption in the Residential sector occurs in the single-family detached/duplex category of dwellings. Attached/row housing/triplexes & quads accounts for almost all the rest, with less than 0.1% consumed in mobile and other.

In addition, the Southern service region accounts for nearly 77% of the residential natural gas consumption in the total Union Service Area.

Reference Case

In the absence of new Union DSM initiatives, the study estimates that natural gas consumption in Union's Residential sector will grow from 2,925 million m^3 in 2007 to about 2,999 million m^3 by 2017. This represents an overall growth of about 2.5% in the period and compares very closely with Union's load forecast, which also included consideration of the impacts of "natural conservation".

Economic Potential Forecast

Under the conditions of the Economic Potential Forecast,[4] the study estimated that natural gas consumption in Union's Residential sector would decline from the Base Year levels of 2,925 million m^3 to about 2,332 million m^3 by 2017. Annual savings relative to the Reference Case are 666 million m^3, or about 23%.

Achievable Potential

As noted above, the Achievable Potential is the proportion of the economic natural gas savings that could be realistically achieved within the study period under various program spending and marketing conditions.

Under the conditions defined by the Financially Unconstrained scenario, total Residential sector natural gas savings in 2017 are estimated to be approximately 357 million m^3/yr. This represents a saving of approximately 12%, relative to the Reference Case, and is equal to approximately 54% of the savings identified in the Economic Potential Forecast.

The most significant opportunities for natural gas savings in this scenario are technologies that reduce space heating requirements. Air sealing in older homes is, however, a particularly large opportunity in this scenario together with high-performance windows and programmable thermostats.

Under the conditions defined by the Static Marketing scenario, total Residential sector natural gas savings in 2017 are estimated to be approximately 261 million m^3/yr. This represents a saving of approximately 9%, relative to the Reference Case, and is equal to approximately 39% of the savings identified in the Economic Potential Forecast.

The most significant opportunities for natural gas savings are technologies that reduce space heating requirements, such as high-performance windows, programmable thermostats and air sealing in older homes.

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[4] The level of natural gas consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost effective. In this study, "cost effective" means that the technology upgrade passes the measure Total Resource Cost (TRC) test.

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Appendices

List of Exhibits

1. INTRODUCTION

1.1 BACKGROUND AND OBJECTIVES

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Union has been participating in a market of increasing DSM program maturity. This market is continually evolving in its engagement with energy efficiency through growing voluntary initiatives and more stringent codes and standards. In addition, changes in the economy have started to show signs of negatively impacting the commercial and industrial marketplace in Union's Service Area.

In the DSM Generic Proceeding held in 2006, Union committed to creating an updated Market Potential Study for input into the next DSM plan. This study will support the identification of potential energy savings for Union's next multi-year plan and be part of Union's regulatory filing in the next DSM rate case.

Union has initiated this current study within the context of the conditions noted above. When completed, the results of this natural gas Efficiency Potential Study will provide a foundation that Union can use to guide the development of its longer-term DSM strategy, including new measures and targets. More specifically, this includes support for Union's filing to the OEB regulatory application for the next multi-year DSM plan by:

- Estimating the achievable and economic potential for DSM measures across all applicable technologies, markets and sectors in Union's Service Area

- Giving shape to, and refining, ongoing energy-efficiency work by Union in order to develop its next multi-year DSM plan, and

- Provide information that is actionable and can be easily converted to plan and program development.

1.2 STUDY SCOPE

The scope of this study is summarized below.

- **Sector Coverage:** The study addresses three sectors: Residential, Commercial[5] and Industrial.

- **Geographical Coverage**: The study results are presented for the total Union Service Area and for two service regions: Southern and Northern. The southern region of Union's system extends through Southwestern Ontario from Windsor to just west of Toronto. The Northern region of Union's system extends throughout Northern Ontario from the Manitoba border to the North Bay/Muskoka area and across Eastern Ontario from Port Hope to Cornwall. The study results are disaggregated by service region due to differences in building stock and weather conditions (heating degree days).

- **Study Period**: This study covers a 10-year period. The Base Year is the calendar year 2007, with milestone periods at five-year increments: 2012 and 2017. The Base Year of 2007 was selected as it is the most recent calendar year for which complete customer data are available.

- **Technologies:** As shown in Exhibit 1.1, this study addresses a broad selection of natural gas energy-efficiency measures.

[5] Throughout this report the term "Commercial" also includes institutional sectors, such as schools, hospitals, etc., unless otherwise noted.

Exhibit 1.1: Residential Energy-Efficiency Technologies

Building Envelope
- High-Performance (ENERGY STAR®) Windows
- Super High-Performance Windows
- Retrofit Windows with Low-E Films
- Air Leakage Sealing
- Attic Insulation
- Wall Insulation
- Foundation Insulation
- Crawlspace Insulation
- Vacuum Panel Insulation
- Air Leakage Sealing and Insulation (Old Homes)

New Building Design
- High-Performance Homes (EGH 80/ R2000/ENERGY STAR®)
- Under-Slab Insulation

Space Heating and Ventilation Equipment
- Condensing Furnaces
- Condensing Boilers
- High-Efficiency Heat Recovery Ventilators (HRVs)
- Programmable Thermostats
- Integrated Mechanical System (Heating and DHW)
- Gas-Fired Heat Pumps
- Duct Sealing
- Furnace Tune-Ups
- Furnace Filter Alarms
- EnerGuide Natural Gas Fireplaces
- Solar Pre-Heated Make-Up Air (e.g., SolarWall®)

Domestic Hot Water
- Ultra Low-Flow Showerheads
- Hot Water Pipe Insulation
- DHW Heat Trap
- DHW Temperature Reduction
- Water Heater Timers
- Condensing Water Heaters
- Tankless Gas-Fired DHW
- Wastewater Heat Recovery
- Solar Hot Water Systems (DHW)
- DHW Recirculation Systems (e.g. Metlund D'MAND®)

Major Appliances
- High-Efficiency Gas Ranges
- High-Efficiency Gas Dryers
- DHW Savings from Efficient Dishwashers
- DHW and Dryer Savings from Efficient Clothes Washers
-

Pool Heaters
- Insulating Swimming Pool Covers
- High-Efficiency Pool Heaters
- Solar Pool Heaters

1.2.1 Data Caveat

As in any study of this type, the results presented in this report are based on a large number of important assumptions. Assumptions such as those related to the current penetration of energy-efficient technologies, the rate of future growth in Union's customer base and customer willingness to implement new energy-efficiency measures are particularly influential.

Wherever possible, the assumptions used in this study are consistent with those used by Union and are based on best available information, which in many cases includes the professional judgement of the consultant team, Union personnel and/or local experts. The reader should use the results presented in this report as best available estimates; major assumptions, information sources and caveats are noted throughout.

1.3 DEFINITIONS[6]

This study employs numerous terms that are unique to analyses such as this one and consequently it is important to ensure that readers have a clear understanding of what each term means when applied to this study. Below is a brief description of some of the most important

[6] A Glossary is provided in Section 9.

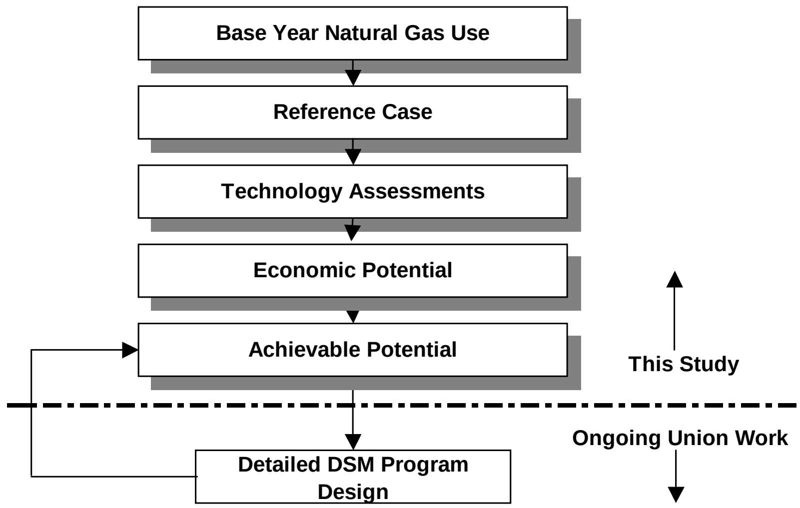
terms. A more comprehensive set of definitions may be found in the Glossary section of this report.

Base Year Natural Gas Use	The Base Year is the starting point for the analysis. It provides a detailed description of "where" and "how" natural gas is currently used in the Residential sector. A bottom up profile of energy use patterns and market shares of energy-using technologies was calibrated to actual Union customer sales data.
Reference Case Forecast	The reference case is a projection of natural gas consumption to 2017, in the absence of any new Union DSM market interventions after 2008. It is the baseline against which the scenarios of energy savings are calculated. The reference case forecast incorporates an estimation of "natural conservation", namely, changes in end-use efficiency over the study period that are projected to occur in the absence of new market interventions.
Measure Total Resource Cost (TRC)	The measure TRC calculates the net present value of energy and water savings that result from an investment in an efficiency technology or measure. The measure TRC is equal to its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy and equipment operating and maintenance (O&M) costs. This calculation includes, among others, the following inputs: the avoided natural gas, electricity and water supply costs, the life of the technology and the selected discount rate, which in this analysis has been set at 10%. The measure TRC test is the primary determinant of whether a measure is included in the economic potential forecast.
Economic Potential Forecast	The Economic Potential Forecast is the level of natural gas consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost effective, from Union's perspective. All of the energy-efficiency technologies and measures that have a positive measure TRC are incorporated into the Economic Potential Forecasts. These technologies and measures are applied at either natural stock turnover rates or at designated years for immediate application.
Achievable Potential	The Achievable Potential is the proportion of the natural gas savings identified in the Economic Potential Forecast that could realistically be achieved within the study period. Achievable Potential recognizes that it is difficult to induce customers to purchase and install all of the efficiency technologies that meet the criteria defined by the Economic Potential Forecast.

1.4 APPROACH

To meet the objectives outlined above, the study was conducted within an iterative process that involved a number of well-defined steps. At the completion of each step, the client reviewed the results and, as applicable, revisions were identified and incorporated into the interim results. The study then progressed to the next step. A summary of the steps is presented in Exhibit 1.2 and briefly discussed below.

Exhibit 1.2: Major Study Steps



Year Calibration Using Actual Union Gas Billing Data

- Compile and analyze available data on Union’s existing building stock, including both customer billing data and information from residential end-use surveys
- Develop detailed technical descriptions of the existing building stock
- Divide building stock into logical regions and sub sectors
- Undertake computer simulations of energy use in each building type and compare these with actual building billing and audit data, including data from the EnerGuide for Houses and ecoENERGY Retrofit program[7] databases
- Compile actual Union billing data
- Create sector model inputs and generate results (where the sector model is the macro model for an entire sector, such as the Residential sector)
- Calibrate sector model results using actual utility billing data.
- The output of Step 1 forms Section 2 of this report.

Step 2: Develop Reference Case Forecast for the Study period

- Compile and analyze building design, equipment and operations data and develop detailed technical descriptions of the new building stock
- Develop computer simulations of energy use in each new building type

[7] EnerGuide for Houses, and its successor ecoENERGY Retrofit, were created by the Government of Canada to help homeowners get independent, expert advice about the energy efficiency of their homes. Developed by the Office of Energy Efficiency (OEE) of Natural Resources Canada (NRCan), in cooperation with CMHC, these programs have supported a pool of qualified energy experts to provide homeowners with information on energy-efficient improvements for their homes. The Government of Canada provides grants to homeowners who complete energy-efficiency retrofits based on the advisors' recommendations. The grant amount depends on a comparison of the pre-retrofit and post-retrofit EnerGuide for Houses rating of the home.

- Compile data on forecast levels of building stock growth and "natural" changes in equipment efficiency levels and/or practices
- Define sector model inputs and create forecasts of energy use for each of the milestone years
- Compare sector model results with Union's forecast for the period.
- The output of Step 2 forms Section 3 of this report.

Step 3: Develop and Assess Energy-efficiency Upgrade Options
- Develop list of energy-efficiency measures
- Compile detailed cost and performance data for each measure
- Identify the baseline technologies employed in the Reference case using secondary research, the Residential End-use Survey, and client consultation
- Develop energy-efficiency upgrade options for each end use
- Determine the measure TRC for each upgrade option
- The output of this task forms Section 4 of this report.

Step 4: Estimate Economic Energy Savings Potential
- Compile utility economic data on the forecast cost of new natural gas supply
- Screen the identified energy-efficiency upgrade options from Step 3 against the utility economic data
- Identify the combinations of energy-efficiency upgrade options and building types where the measure TRC is positive
- Apply the economically attractive efficiency measures from Step 3 within the energy use simulation model developed previously for each building type
- Determine annual energy consumption in each building type when the economic efficiency measures are employed
- Compare the energy consumption levels when all economic efficiency measures are used with the Reference case consumption levels and calculate the energy savings
- The output of this task forms Section 5 of this report.

Step 5: Estimate Achievable Energy Savings Potential
- "Bundle" the energy saving opportunities identified in the Economic Potential Forecast into a set of Actions
- Create "Action Profiles" for each of the identified Actions that provide a "high-level" rationale and direction, including target technologies and sub-markets as well as key barriers and a broad intervention strategy
- Review historical achievable program results and prepare preliminary Action Assessment Worksheets
- Conduct achievable potential workshops involving utility and consultant team personnel, selected trade allies and technology and market experts to reach general agreement on a range of achievable potential based on different funding scenarios
- The output of this task forms Section 6 of this report.

1.5 ANALYTICAL MODELS

The analysis of the Residential sector employed two linked modeling platforms as follows:

- **HOT2000,** a commercially supported, residential building energy-use simulation software

- **RSEEM** (Residential Sector Energy End-use Model), a Marbek in-house spreadsheet-based macro model.

HOT2000 was used to define household heating, cooling and domestic hot water (DHW) energy use for each of the residential building archetypes. HOT2000 uses state-of-the-art heat loss/gain and system modeling algorithms to calculate household energy use. It addresses:

- Electric, natural gas, oil, propane and wood space heating systems
- DHW systems from conventional to high-efficiency condensing systems
- The interaction effect between space heating appliances and non-space heating appliances, such as lights and refrigerators.

The outputs from HOT2000 provide the space heating/cooling energy-use intensity (EUI) inputs for the thermal archetype module of RSEEM.

RSEEM consists of three modules:

- A General Parameters module that contains general sector data (e.g., number of dwellings, growth rates, etc.)
- A Thermal Archetype module, as noted above, that contains data on the heating and cooling loads in each archetype
- An Appliance Module that contains data on appliance saturation levels, fuel shares, unit energy use, etc.

RSEEM combines the data from each of the modules and provides total use of energy by service region, dwelling type and end use. In this application, the RSEEM model functions as a system for tracking the disaggregation of natural gas consumption down to the level of individual end uses and types of dwellings, so that the effects of natural gas conserving measures can be evaluated at the same level of detail.

HOT2000 models are developed after the estimates of heating and DHW energy consumption have emerged from the RSEEM Base Year analysis. Models are constructed that incorporate information on standard house construction in the utility's service region, but which also mimic the energy performance figures derived from the utility sales data using RSEEM. These models can then be used to test the net improvement in energy performance that will result from various energy conserving measures. The results are fed back into RSEEM to produce estimates of energy-efficiency potential.

1.6 THIS REPORT

This report addresses the Residential sector and provides a summary of the results to date. This initial report is presented in the following sections.

- Section 2 presents a profile of Base Year natural gas use in Union's Ontario service area, including a discussion of the major steps involved and the data sources that were employed.

- Section 3 presents the Residential sector Reference Case for the study period 2007 to 2017.

- Section 4 provides a financial and economic assessment of the identified Residential sector energy-efficiency measures.
- Section 5 presents the Residential sector Economic Potential Forecast for the study period 2007 to 2017.
- Section 6 presents the estimated range of Achievable Potential for natural gas savings, under differing scenarios, for the study period 2007 to 2017.
- Section 7 presents the conclusions.
- Section 8 presents a listing of major references.
- Section 9 provides a glossary of commonly used terms.

2. BASE YEAR NATURAL GAS USE

2.1 INTRODUCTION

This section presents a description of natural gas use in Union's Residential sector in the Base Year of 2007. Drawing on the best available data, this section presents total natural gas consumption in Union's Residential sector, together with an estimate of how that consumption is distributed by service area, sub sector, end use and technology.

The remainder of this section outlines the steps involved in preparing the Base Year calibration and presents a summary of the results. The discussion is organized into the following subsections:

- Segmentation of residential building stock
- Estimation of net space heating loads
- Annual appliance energy use
- Appliance saturation
- Natural gas fuel share by end use
- Base Year average natural gas use, by dwelling type
- Summary of model results.

2.2 SEGMENTATION OF RESIDENTIAL BUILDING STOCK

The first major task in developing the description of Base Year natural gas consumption involved the segmentation of the residential building stock on the basis of three factors:

- Dwelling type
- Heating category (natural gas, electric)
- Service area.

As agreed at the study's outset, dwelling types used in this analysis are:

- Single-family detached/duplex
- Attached/Row/Multi (including all row houses, townhouses, triplexes, and quads)
- Other/Mobile

Union customer billing data were used to develop a composite breakdown of the Residential sector by dwelling type. This information is summarized in Exhibit 2.1 and highlights are presented below:

- There are about 1.1 million dwelling units in the regions served by Union
- On a regional basis, almost 77% of dwelling units are in the Southern region and the remaining 23 % are located in the Northern region
- On the basis of dwelling type, 94% of the residential stock is single-family. Almost all of the rest fall in the Attached/Row/Multi category. Only one-tenth of one percent (0.1%) are mobile homes or other residential buildings (such as heated sheds).
- In terms of fuel share, approximately 93% of Union residential customers use natural gas as their primary heating fuel.

Exhibit 2.1: Base Year (2007) Residential Units, by Dwelling Type, Heating Source and Service Region

Segment	Residential Units		
	Southern Region	Northern Region	Total
Single-Family Detached/ Duplex- Gas Heated	717,861	221,799	939,660
Single-Family Detached/ Duplex- Non-Gas Heated	70,997	36,107	107,104
Attached/Row Housing/Tris & Quads	93,131	7,926	101,057
Other	779	617	1,396
Subtotal	882,768	266,449	1,149,217

2.2.1 Transfers of Dwelling Units Between Residential and Commercial Datasets

The analysis of energy-efficiency opportunities is facilitated if similar types of buildings can be grouped together. To this end, a small number of customers in the residential rate classes that appeared to be large apartment complexes were transferred to the Commercial sector, and a small number of customers in the commercial rate classes that appeared to be small multi-family complexes were transferred to the Residential sector. Both the number of customers and their accompanying volume of consumption were transferred.

In the Southern region, a total of 18,979 apartment and condominium units were transferred to the Commercial sector, along with 21,560,457 m^3 of natural gas consumption. 2,015 multi-family other and row/townhouse complexes were transferred in from the commercial dataset, along with 13,748,546 m^3 of natural gas consumption. Row/townhouse complexes in the Southern region were found to use approximately eight times as much natural gas as townhouse units. The numbers of townhouse complexes, including both the ones that were already in the residential dataset and those transferred from commercial, were multiplied by eight to obtain the number of units.

In the Northern region, a total of 2,303 apartment and condominium units were transferred to the Commercial sector, along with 4,111,227 m^3 of natural gas consumption. 552 multi-family other and row/townhouse complexes were transferred in from the commercial dataset, along with 3,510,218 m^3 of natural gas consumption. Row/townhouse complexes in the Northern region were found to use approximately three times as much natural gas as townhouse units. The numbers of townhouse complexes, including both the ones that were already in the residential dataset and those transferred from commercial, were multiplied by three to obtain the number of units.

2.3 ESTIMATION OF NET SPACE HEATING LOADS

Net space heating load is the space heating load of a building that must be met by the space heating system. This is equal to the total heat loss through the building envelope minus solar and internal gains.

The net space heating loads for single-family detached and row houses in the two service regions were developed based on the following combination of sources:

- Union's residential customer sales data, by dwelling type
- Union's *2007 Residential Penetration Study* (RPS),[8] which provided data showing the saturation of supplementary heating systems, by dwelling type
- Knowledge of the energy consumption and saturation of other natural gas end uses within each residential dwelling type
- Marbek's database of residential energy consumption from other jurisdictions.

The net space heating load for each dwelling type is given by the following equation:

$$NetHL_1 = HL_1 + a_{i,1} * s_{i,1}$$

Where: $NetHL_1$ = Net heating load for dwelling type #1
HL_1 = Load on primary heating appliance for dwelling type #1
$a_{i,1}$ = Average consumption for supplementary heating in dwelling type #1
$s_{i,1}$ = Saturation of supplementary heating in dwelling type #1

For the purposes of this discussion, the focus is on the estimation of the space heating load on the primary heating appliance (HL_1) in the above equation. Note that all dwellings are assumed to have a primary heating appliance (of whatever fuel), so no saturation for the primary heating appliance is included in the equation.

The load on the primary heating appliance (i.e., natural gas furnace or boiler) was estimated for each dwelling type and service region, based on Union's customer sales data for each dwelling type and combined with data on the natural gas consumption of non-space heating end uses and the estimated contribution of natural gas fireplaces. Data specific to Union's Service Area were used wherever possible, with any gaps filled in by drawing on Marbek's database on energy end uses. The values for $a_{i,1}$ and $s_{i,1}$ were developed based on the estimated share of space heating that is provided by natural gas (versus supplementary fuels), as taken from Union's Residential Penetration Study. The natural gas space heating share is not given directly by the data presented in that study, but is estimated based on the surveyed preference for natural gas as a space heating fuel, and the presence of supplementary heating sources in the dwellings.

Exhibit 2.2 summarizes the estimated load on the primary space heating system, by dwelling type and location. These estimates refer to the load that the space heating system must meet after internal heat losses and gains, including fireplaces, are accounted for. Estimated unit energy consumption (UEC) is also shown, based on an average house in which all the space heating load is met by a natural gas furnace of average efficiency.

The values in the exhibit are actually derived in reverse. The analysis starts with the average natural gas consumption for the dwellings and uses all the known data for consumption, saturation, and fuel share for all the end uses in the dwelling to derive the consumption of natural gas for space heating. The estimated fuel share for natural gas space heating is used to arrive at

[8] Union Gas. *2007 Residential Penetration Study – Single Family and New Housing Segments, Top Line Results,* Chatham, ON, January 15, 2008.

the UEC figures. Average furnace efficiency and the conversion factor for MJ/m^3 of natural gas are then used to estimate net space heating loads. These were used to develop the HOT2000 house models.

Exhibit 2.2: Base Year (2007) Residential Units—Estimated Net Space Heating Load (MJ/yr.) and Space Heating UEC[9] (m^3/yr.), for Primary Heating System, by Dwelling Type and Service Region

Segment	Net Space Heating Load (MJ/yr)		Space Heating UEC (m^3)	
	Southern	Northern	Southern	Northern
Single-Family Detached/ Duplex	55,417	61,074	1,801	2,002
Attached/Row Housing/Tris & Quads	37,129	51,143	1,207	1,677
Other	27,228	46,293	885	1,518

A brief discussion of some of the most important variables affecting the net space heating loads provided above is presented below.

2.3.1 Envelope Area and Exposure

Attachment type is the main influence on building envelope area and exposure of buildings. Moving from greatest exposure to least, dwelling types include mobile homes, single-family, duplex, triplexes and quads, and townhouses and row houses. Duplexes are built in a similar fashion to single-family homes but, from an exposure perspective, are more similar to row houses. Townhouses, which also share one or two walls, are, on average, smaller than single-family detached dwellings.

2.3.2 Weather Conditions

The Union Service Area is divided into two service regions: Northern and Southern. The major population centres included in the Southern region are: Brantford, Chatham, Halton, Hamilton, Kitchener-Waterloo, London, Sarnia, Windsor, Burlington, and Guelph. The major population centres included in the Northern region are: Kingston, North Bay, Sault-Ste. Marie, Sudbury, Thunder Bay and Timmins. In each region there is a range in severity of climate, but there is a relatively clear division between the two regions.[10]

For modelling purposes, weather data from London and North Bay were used to create thermal simulations of the Southern and Northern regions, respectively.

2.3.3 Floor Area and Shape

Exhibit 2.3 presents the typical floor area by region and vintage for single-family houses. As shown in the exhibit, there has been a general increase in floor area over time, and

[9] Unit energy consumption (UEC) is the approximate consumption of a natural gas furnace to meet the net space heating load shown, assuming there are no supplementary heating devices and the furnace has an average efficiency of approximately 82%.

[10] The 99% design dry-bulb temperatures for Southern cities ranges from approximately -13ºC in Hamilton to approximately -16ºC in London. The 99% design dry-bulb temperatures for Northern cities ranges from approximately -19ºC in Kingston to approximately -31ºC in Timmins.

houses in the Southern region are generally larger than those in the Northern region. The biggest changes in housing size have occurred since the mid-1980s, when changing demographics and growing affluence resulted in larger floor areas for new homes.

The shapes of houses within the Union Service Area have also changed over the years, as they have in other Canadian provinces. Pre-1970 houses typically have half storeys and simple floor plans. Post-1970 houses are most likely to include split-levels, ranches and two-storey houses, with more complex floor plans. As a result, newer houses generally have more wall area relative to their floor area. In other words, average wall area in new homes is increasing even faster than floor area. Finally, due to the improved performance of newer windows and homebuyers' preferences, the area of glazing has increased by about 15%.

Both this exhibit and the airtightness discussion that follows draw on data from the ecoENERGY Retrofit database. This database currently contains audit data on over 30,000 homes in Ontario. These dwellings are not a random sample; self-selection bias may mean that the sample is skewed. The database does, however, permit the examination of trends in housing construction, such as the variation in floor area with vintage of home, keeping in mind that the relative differences are more reliable and therefore more useful than the absolute numbers. The house models developed for the study are always calibrated back to energy performance derived from utility sales data.

Exhibit 2.3: Typical Floor Areas for Single-family Detached Dwellings by Vintage and Service Region, (m^2)

Vintage	Floor Space including basement area, (m^2)	
	Southern Region	Northern Region
Pre-1980	215.7	198.5
1981-1993	287.0	258.5
Post-1993	308.1	278.2
Number in sample	16,071 dwellings	2,089 dwellings

Notes: 1 m^2 = 10.76 ft^2
Figures include basement area, which averages 30% of totals.
Source: ecoENERGY Retrofit database (Ontario)

2.3.4 Airtightness

Air test data for single-family houses were measured as part of the ecoENERGY Retrofit program, and Exhibit 2.4 summarizes the results by vintage and region. As demonstrated, there has been a continued improvement in the airtightness of buildings in all regions, with the most airtight being newer homes located in the Northern region.

As discussed previously, there is a self-selection bias in the ecoENERGY Retrofit database. However, the trend data, as shown in Exhibit 2.4, is nonetheless useful in developing inputs for the HOT2000 models.

Exhibit 2.4: Average Air Changes per Hour in Single-family Detached Dwellings by Vintage and Service Region, (ACH @ 50 Pa)

Vintage	Southern Region	Northern Region
Pre-1980	9.1	7.1
1981-1993	4.7	4.5
Post-1993	3.9	3.3
Number in sample	16,071 dwellings	2,089 dwellings

Source: ecoENERGY Retrofit database (Ontario)

2.3.5 Heating Set Point

The assumptions made relating to heating set points throughout a dwelling affect the calculation of net space heating load. The set points employed in the HOT2000 simulations were 20.8ºC for main and upper floors and 19.8ºC for basements. These set points were selected based on averages obtained from the EnerGuide for Houses database.

2.3.6 Average Furnace Efficiency

Union's 2007 Residential Penetration Study provides data on the distribution of high-efficiency, mid-efficiency, and standard efficiency furnaces in the surveyed population of homes. The distribution was combined with an assumed efficiency for each category, to arrive at an approximate average efficiency of the existing stock of furnaces in the Union Service Area. As shown in Exhibit 2.5, the approximate average efficiency is 82%.

Exhibit 2.5: Calculation of Average Efficiency of Existing Stock of Furnaces

Furnace Type	Assumed Efficiency	Distribution	Efficiency x Distribution
Conventional	68%	30%	20%
Mid-Efficiency	78%	21%	16%
High-Efficiency	90%	50%	45%
Average Efficiency of Existing Stock of Furnaces			81.8%

Sources: Distribution is from the *2007 Residential Penetration Study*. The average efficiency calculated here agrees well with the Residential Furnace Efficiency Index used in Union's forecasting process.

2.3.7 Fireplace Contribution to Space Heat Load

The contribution to space heating made by fireplaces (natural gas, propane or wood) and woodstoves is not included in the net space heating loads presented in Exhibit 2.2. The fireplace contribution is highly variable. Modern fireplaces that take combustion air from outside the house make a heating contribution, albeit at a much lower efficiency than a condensing furnace (the maximum efficiency of a natural gas fireplace is approximately 77%). Fireplaces that draw combustion air from the room operate at efficiencies as low as

25%. Decorative natural gas log sets can have efficiencies of 0% and consume as much natural gas as heating fireplaces, while contributing no net heat to the dwelling. Wood fireplaces that draw combustion air from the room and have dampers that are not properly closed when the fireplace is not in use can actually cause a net heat loss to the dwelling.

Due to this variability, fireplaces are treated as a separate end use and are separated from the space heating end use (see Section 2.4.5).

2.3.8 Supplemental Heating

Union's 2007 Residential Penetration Study data show that 45% of its residential customers have some form of supplementary space heating equipment. More specifically:

- 72% of customers with supplementary heating equipment have fireplaces and 6% have wood-burning stoves, all of which are treated under the fireplaces end use in this study.

- 16% of customers with supplementary space heating equipment have electric baseboard heaters, 15% have portable electric heaters, 3% have space heaters and 0.3% have heat pumps.

Since only 7% of Union customers heat predominantly with a fuel other than gas, most of the baseboards, portable electric heaters and space heaters are used for supplemental heating in a gas-heated home. Portable electric heaters are more frequently found in older homes, according to residential market survey work in other jurisdictions.

In addition to fuel conversions and substitutions, there are many home renovations and additions that have involved the installation of electric space heating in previously non-electrically heated houses. Electric baseboards are a convenient, low first-cost installation for a new room in an existing house. This phenomenon has been occurring since the mid-1960s and growing in proportion to the rapidly increasing rates of renovation and addition building in the 1970s and 1980s. Renovations to add electric baseboards would be more likely in older homes, because newer homes are less likely to have required an addition.

Determining the number of homes with supplementary electric heating is only the first step in estimating the actual energy consumption of the heating appliances. The percentage of floor space heated by electric heaters, the thermostat set point in the rooms with electric baseboards (often set lower than the main furnace thermostat) and the runtime of portable heaters are important factors. The overall heating fuel share for electric supplementary heating devices is estimated to be 5%, in addition to the share from primary electric heating.

In homes with a primary heating fuel other than gas, there is very little supplemental heating with natural gas appliances. The natural gas fuel share for supplementary heat is therefore essentially zero.

2.4 ANNUAL APPLIANCE ENERGY USE

Exhibits 2.6 and 2.7 summarize the estimated average annual UEC for each of the major natural gas appliances included in this study for the Southern and Northern service regions, respectively.

The values shown in Exhibits 2.6 and 2.7 apply to the current stock mix; the values vary slightly by service region, primarily due to differences in weather, dwelling size and/or occupancy levels.

Exhibit 2.6: Annual Base Year Appliance Natural Gas Use (UEC) for the Southern Service Region (m^3/yr.)

Segment	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use
	m^3/yr.	m^3/yr.	m^3/yr.	m^3/yr.	m^3/yr.	m^3/yr.
Single-Family Detached/ Duplex	660	278	122	131	2,012	80
Attached/Row Housing/Tris & Quads	473	199	68	73	1,440	57
Other	317	134	46	49	967	39

Exhibit 2.7: Annual Base Year Appliance Natural Gas Use (UEC) for the Northern Service Region (m^3/yr.)

Segment	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use
	m^3/yr.	m^3/yr.	m^3/yr.	m^3/yr.	m^3/yr.	m^3/yr.
Single-Family Detached/ Duplex	650	309	115	128	2,237	80
Attached/Row Housing/Tris & Quads	465	221	78	72	1,601	57
Other	312	149	52	48	1,074	39

Further discussion is provided below for each end-use appliance.

2.4.1 Domestic Hot Water

UEC estimates for DHW are drawn from several sources. Hot water consumption estimates developed for previous studies were compared against the estimate of gas consumption from Union's internal estimates, which are based on a review of external literature, customer surveys and engineering estimates. The resulting estimates were adjusted for the estimated average number of occupants in the different housing segments.

Detached homes have more occupants on average than attached homes, according to the residential surveys carried out in several jurisdictions and Statistics Canada's table of average household sizes for Ontario, as shown in Exhibit 2.8.[11] Exhibit 2.8 also indicates that the average number of occupants is slightly higher in Southern region homes than it is in Northern region homes. This latter difference is somewhat mitigated by a difference in average ground temperature. The cold water inlet to the DHW system in North Bay is, on average, more than 3°C colder than in London.

[11] Statistics Canada. *Private households by structural type of dwelling, by province and territory* (2006 Census).

The end use modeling in this study is primarily driven by utility customer and sales data showing average sales of natural gas to each household type, by survey results indicating the penetration of different types of gas-using appliances in the households, and by house modeling to estimate the effects of climate on space heating consumption. The best fit between the model and the data requires that end uses affected by household occupancy (DHW, cooking and clothes drying) consume slightly less natural gas in the average Northern region household than in the average Southern region household. The regional variation in occupancy indicated in Exhibit 2.8 provides confirmation of this approach.

Exhibit 2.8: Household Occupancy in Ontario, by Dwelling Type and Municipality

Region	Municipality	Single-Detached	Apartment, 5 or more Storeys*	Mobile	Other (Attached, etc.)	Weighted Average
South	**Hamilton**	2.9	1.7	2.2	2.3	2.6
	London	2.8	1.6	1.7	2.2	2.4
	Windsor	2.8	1.5	1.8	2.1	2.5
North	**Sudbury**	2.7	1.4	2.2	2.0	2.4
	Thunder Bay	2.6	1.3	2.3	1.9	2.3
Ontario Average		2.9	2.0	2.1	2.4	2.6

* Apartments are excluded from the residential analysis for this study.

Exhibit 2.9 shows the estimated distribution of DHW load by major end use.

Exhibit 2.9: Distribution of DHW Energy Use by End Use in Existing Stock

End Use	Energy Use (m^3/yr.)	%
Personal Use	231	35
Dishwashing	152	23
Clothes Washing	178	27
Standby Losses	99	15
Total	660	100

2.4.2 Cooking

UEC estimates for the existing stock of cooking appliances were obtained from Union internal estimates, which are based on a review of external literature, customer surveys and engineering estimates. Energy consumption was adjusted for occupancy rates.

2.4.3 Dryers

UEC estimates for the existing stock of gas dryers were obtained from Union internal estimates, which are based on a review of external literature, customer surveys and engineering estimates. They were subsequently adjusted for occupancy rates.

2.4.4 Pool Heaters

Union has internal UEC estimates for the existing stock of pool heaters, based on a review of external literature, customer surveys and engineering estimates. Based on preceding work for utilities across Canada, these estimates were adjusted upwards. On average, pool heaters are expected to have similar annual energy consumption to a residential furnace.

Union's 2007 Residential Penetration Study identified the percentage of customers in each of four regions with pool heaters. This additional information was used to adjust the pool heater average consumption for the Union Service Area. The resulting average figure was adjusted for climate differences between the regions.

2.4.5 Fireplaces

UEC estimates for the existing stock of fireplaces were obtained from Union internal estimates, which are based on a review of external literature, customer surveys and engineering estimates. These were adjusted based on Union's 2007 Residential Penetration Study, which contains detailed penetration data for gas fireplaces; it also provides data on the number of fireplaces per home and the incidence of wood-burning, electric and natural gas fireplaces.

2.4.6 Other

A variety of other gas end uses are found in the homes of Union residential customers, including gas barbecues, spa/hot tub heaters, outdoor fireplaces or campfires, garage or patio heaters and outdoor gas lights. These end uses each account for a small portion of Union's residential load and are therefore not modeled separately. The model does not specifically track other end uses that consume fuels other than natural gas or electricity.

2.4.7 Electric End Uses

Marbek's energy model tracks energy consumption for both electricity and natural gas. Several electrical end uses, such as furnace fans and air conditioning systems, are directly affected by some of the efficiency measures applicable to natural gas space heating. The electrical savings attributable to these measures are factored into the measure TRC results presented in Section 4.

2.5 APPLIANCE SATURATION

Exhibits 2.10 and 2.11 summarize the appliance saturation[12] levels assumed for the Southern and Northern regions, respectively. End-use saturation figures are from Union's 2007 Residential Penetration Study.

[12] Saturation refers to the incidence of each appliance within each dwelling type, regardless of the type of fuel that is used to operate it.

The term "saturation," as used in this study, refers to the presence of an end use in the dwelling, regardless of what fuel it uses. For end uses where the most convenient unit of analysis is the dwelling (such as DHW), saturation refers to the percentage of dwellings that have that end use. Virtually all dwellings have DHW, so the saturation is 100%. For end uses where the most convenient unit of analysis is the appliance (such as dryers), the saturation indicates the average number of appliances per dwelling. A saturation of 97% indicates that in an average group of 100 dwellings, there would be 97 dryers (which could be either gas or electric).

To calculate the penetration of gas appliances in Union's service regions, the saturation can be multiplied by the gas fuel share shown in Exhibits 2.12 and 2.13. The result of this calculation should be comparable to the penetrations found in Union's 2007 Residential Penetration Study.

Exhibit 2.10: Base Year Appliance Saturation Levels for the Southern Service Region (%)

Segment	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use
	%	%	%	%	%	%
Single-Family Detached/ Duplex	100%	54%	100%	97%	6%	100%
Attached/Row Housing/Tris & Quads	100%	54%	100%	97%	6%	100%
Other	100%	54%	100%	97%	6%	100%

Exhibit 2.11: Base Year Appliance Saturation Levels for the Northern Service Region (%)

Segment	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use
	%	%	%	%	%	%
Single-Family Detached/ Duplex	100%	54%	100%	97%	3%	100%
Attached/Row Housing/Tris & Quads	100%	54%	100%	97%	3%	100%
Other	100%	54%	100%	97%	3%	100%

2.6 NATURAL GAS FUEL SHARE

Exhibits 2.12 and 2.13 summarize the estimated natural gas fuel shares by end use for the Southern and Northern regions, respectively.

The fuel share of 100% for "Other Gas" reflects the fact that "Other" end uses that do not use gas are treated in a separate category within the model (but are not shown in these exhibits).

These figures come from Union's 2007 Residential Penetration Study. As discussed previously, space heating fuel shares are challenging because there are data on the presence of auxiliary heating devices, but not on how much they are used. The values shown reflect the most reasonable assumptions based on Marbek's engineering judgment and experience.

Exhibit 2.12: Base Year Natural Gas Fuel Shares for the Southern Service Region (%)

Segment	Space Heating	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use
	%	%	%	%	%	%	%
Single-Family Detached/ Duplex	91%	94%	72%	26%	44%	81%	100%
Attached/Row Housing/Tris & Quads	91%	94%	72%	26%	44%	81%	100%
Other	91%	94%	72%	26%	44%	81%	100%

Exhibit 2.13: Base Year Natural Gas Fuel Shares for the Northern Service Region (%)

Segment	Space Heating	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use
	%	%	%	%	%	%	%
Single-Family Detached/ Duplex	86%	86%	68%	12%	35%	81%	100%
Attached/Row Housing/Tris & Quads	86%	86%	68%	12%	35%	81%	100%
Other	86%	86%	68%	12%	35%	81%	100%

2.7 BASE YEAR (2007) AVERAGE NATURAL GAS CONSUMPTION PER DWELLING UNIT

Exhibits 2.14 and 2.15 combine the efficiency, saturation and fuel share data presented in the preceding exhibits and shows the resulting energy use, by end use, for each dwelling type in the Southern and Northern regions, respectively

Exhibit 2.14: Base Year (2007) Average Natural Gas Use per Dwelling Unit in the Southern Service Region (m^3/yr)

Segment	Space Heating	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use	TOTAL
	m^3/yr.	m^3/yr.	m^3/yr.	m^3/yr.	m^3/yr.	m^3/yr.	m^3/yr.	m^3/yr.
Single-Family Detached/ Duplex	1,639	617	108	31	55	97	80	2,628
Attached/Row Housing/Tris & Quads	1,098	442	77	17	31	69	57	1,792
Other	805	297	52	12	21	47	39	1,271

Note: Any difference in totals is due to rounding.

Exhibit 2.15: Base Year (2007) Average Natural Gas Use per Dwelling Unit in the Northern Service Region (m^3/yr)

Segment	Space Heating	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use	TOTAL
	m^3/yr.	m^3/yr.	m^3/yr.	m^3/yr.	m^3/yr.	m^3/yr.	m^3/yr.	m^3/yr.
Single-Family Detached/ Duplex	1,722	559	114	14	44	51	80	2,583
Attached/Row Housing/Tris & Quads	1,442	400	81	9	24	36	57	2,051
Other	1,305	269	55	6	16	24	39	1,714

Note: Any difference in totals is due to rounding.

2.7.1 Sample Calculations

The following examples illustrate the method used to generate the values shown in the preceding Exhibits 2.14 and 2.15. Exhibits 2.16 and 2.17 show how the data from the previous exhibits are combined to estimate annual natural gas use for, respectively, primary space heating and appliances.

Exhibit 2.16: Sample Calculation of Annual Space Heating Natural Gas Use for a SFD/Duplex in the Southern Region

Primary Space Heat load, from Exhibit 2.2	55,417 MJ/yr.
Average Furnace Efficiency	81.8%
Assumed Heating Content of Fuel	37.62 MJ/m^3
Saturation of Heating as an End use	100%
Natural Gas Fuel Share, from Exhibit 2.12	91%

Annual Space Heating UEC = 55,417 / 81.8% /37.62 = 1,801 m^3/yr. (as shown in Exhibit 2.2)

Annual Natural Gas Use = 1,801 m^3/yr. x 100% x 91% = 1,639 m^3/yr. (as shown in Exhibit 2.14)

The penetration of natural gas heating would be obtained by multiplying saturation (100%) by fuel share (91%) to get 91%. In the case of space heating, the fuel share is the percentage of dwellings whose primary heating appliance is gas-fired, reduced by the estimated percentage of heating load that is met by non-gas supplementary heating devices.

Exhibit 2.17: Sample Calculation of Annual DHW Natural Gas Use in SFD/Duplex in the Southern Region

UEC, from Exhibit 2.6	660 m^3/yr.
Saturation, from Exhibit 2.10	100%
Natural Gas Fuel Share, from Exhibit 2.12	93.5% (rounded to 94% in the exhibit)

Annual DHW Natural Gas Use = 660 x 100% x 93.5% = 617 m^3/yr. (as shown in Exhibit 2.14)

The penetration of natural gas DHW would be found by multiplying the saturation (100%) by the natural gas fuel share (93.5%), to get 93.5%.

2.8 SUMMARY OF MODEL RESULTS

This section presents the results of the model runs for the Base Year 2007. They are presented in three separate exhibits:

- Exhibit 2.18 presents the model results for the total Union Service Area. The results are broken out by dwelling type and end use. Exhibit 2.18 also includes a pie chart showing gas consumption by end use.

- Exhibits 2.19 and 2.20 present the same results for each of the service regions defined for this study.

Exhibit 2.18: Base Year (2007) Natural Gas Consumption in the Total Union Gas Service Area (1000 m^3/yr.)

Segment	Space Heating	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use	Totals
	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.
Single-Family Detached/ Duplex	1,737,149	631,184	114,694	28,140	54,695	89,580	83,956	2,739,396
Attached/Row Housing/Tris & Quads	113,708	44,320	7,859	1,684	3,060	6,751	5,801	183,183
Other	1,433	397	74	13	26	51	54	2,048
TOTAL	1,852,289	675,900	122,627	29,837	57,781	96,382	89,810	2,924,627

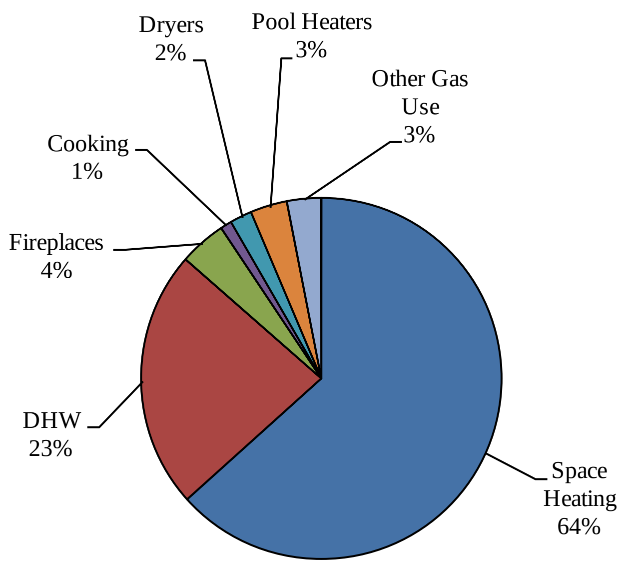


Exhibit 2.19: Base Year (2007) Natural Gas Consumption in the Southern Service Region (1000 m^3/yr)

Segment	Space Heating	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use	Totals
	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.
Single-Family Detached/ Duplex	1,293,067	487,016	85,388	24,584	43,452	76,498	63,270	2,073,275
Attached/Row Housing/Tris & Quads	102,280	41,149	7,215	1,610	2,867	6,463	5,346	166,930
Other	627	231	41	9	16	36	30	990
TOTAL	1,395,974	528,396	92,643	26,203	46,335	82,997	68,646	2,241,195

Exhibit 2.20: Base Year (2007) Natural Gas Consumption in the Northern Service Region (1000 m^3/yr.)

Segment	Space Heating	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use	Totals
	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.
Single-Family Detached/ Duplex	444,082	144,168	29,306	3,555	11,243	13,082	20,685	666,121
Attached/Row Housing/Tris & Quads	11,428	3,171	645	74	193	288	455	16,254
Other	805	166	34	4	10	15	24	1,057
TOTAL	456,315	147,505	29,984	3,634	11,446	13,385	21,164	683,432

2.8.1 Interpretation of Results

Selected highlights of the information presented in Chapter 2 are presented below.

Segments

Nearly 94% of the natural gas consumption in the Residential sector occurs in the single-family detached/duplex category of dwellings. Attached/row housing/triplexes & quads accounts for almost all the rest, with less than 0.1% consumed in mobile and other.

End Use

Space heating accounts for 64% of natural gas consumption in the Residential sector. DHW consumes approximately 23%. Fireplaces consume about 4% and pool heaters consume approximately 3%. Natural gas dryers consume approximately 2% and natural gas ranges consume approximately 1% of the natural gas consumption in the Residential sector.

Service Region

The Southern Service region accounts for nearly 77% of the residential natural gas consumption in Union's Service Area.

Characteristics of Existing Housing

The stock of housing in the Union Gas service territory varies considerably with the age of the house. Building code changes in Ontario have increasingly stressed energy efficiency, improving the air tightness and insulation requirements in new home construction. The high efficiency, condensing furnace has also become the norm in new homes. Countering these trends towards reduced consumption, newer houses are typically larger than houses built in previous decades and have more and larger windows.

Stratifying housing by year of construction can be useful in evaluating some efficiency upgrades. An envelope improvement measure that does not appear viable in an average house may be attractive in older houses with low insulation values and large space heating loads. Stratifying Union's residential survey by year of construction would improve the analysis of such measures.

3. REFERENCE CASE NATURAL GAS USE

3.1 INTRODUCTION

This section presents the Residential sector Reference Case for the study period 2007 to 2017. The Reference Case estimates the expected level of natural gas consumption that would occur over the study period in the absence of new Union DSM initiatives. Thus, the Reference Case provides the point of comparison for the calculation of opportunities associated with each of the subsequent scenarios that are assessed within this study.

The Reference Case discussion is presented within the following subsections:

- Estimation of net space heating loads – new dwellings
- "Natural" changes to space heating loads – existing dwellings
- "Natural" changes to appliance energy use
- Stock growth
- Fuel shares and saturation levels
- Summary of model results.

3.2 ESTIMATION OF NET SPACE HEATING LOADS – NEW DWELLINGS

The first task in building the Reference Case involved estimating the net space heating loads for new buildings. Since building envelope is the single largest determinant of a building's space heating load, it was important to assess changes in building codes and standards that would affect the building envelope of new homes.

The Ontario Building Code (OBC) was recently amended (O. Reg. 350/06), with several changes coming into effect on December 31, 2006, and others scheduled to come into effect sequentially until the end of 2011. The 2006 Building Code includes over 700 technical changes from the 1997 version; many of these changes significantly increase the energy efficiency of new buildings. OBC changes that are particularly relevant to this Reference Case include:

- Minimum requirements for the thermal resistance of building insulation are increased, as presented in Exhibit 3.1.

- Minimum AFUE (Annual Fuel Utilization Efficiency) of natural gas- and propane-fired furnaces are increased to 90%.

- Effective at the end of 2008, near-full height basement insulation will require that basement insulation in new homes extend at least down to 0.38 m (15 inches) above the basement floor.

Exhibit 3.1: Minimum Thermal Resistance of Insulation (RSI) for Residential Buildings, (m^2·°C/W)

Assembly	Thermal Resistance (RSI)* Required			
	1997 Building Code (O.Reg. 403/97)		2006 Building Code (O.Reg. 350/06)	
	Less than 5,000 Degree Days	5,000 or More Degree Days	Less than 5,000 Degree Days	5,000 or More Degree Days
Ceiling below Attic or Roof Space	5.40	6.70	7.24	7.24
Roof without Attic or Roof Space	3.52	3.52	5.21	5.21
Walls (Non-Foundation)	3.00	3.87	3.80	4.67
Foundation Walls	1.41	2.11	2.40	2.40
Floors (Non Slab-on-Ground)	4.40	4.40	4.70	4.70
Slab-on-Ground (with Heating Pipes, Tubes, Ducts, or Cables)	1.76	1.76	2.11	2.11
Slab-on- Ground (without Heating Pipes, Tubes, Ducts, or Cables)	1.41	1.41	1.76	1.76

NOTE: Degree days refers to the number of degree days below 18°C

Although still at the proposal stage, the new OBC would require new homes built in 2012 and later to meet standards that are in accordance with EnerGuide for Homes (EGH 80). This is substantially higher than current standards. Based on the ecoENERGY Retrofit database, the average EnerGuide rating of new homes prior to the 2006 update of the OBC was about 73. Improvement to EGH 80 would result in about a 26% space heating reduction for new homes compared to the pre-2006 standard of construction.[13] However, this component of the proposed changes to the OBC remains under active debate; consequently, the scope and timing of this proposed change remains uncertain.

Given these uncertainties, the Reference Case assumes a gradual thermal improvement for new homes constructed over the study period. The average new house is assumed to reach a rating of approximately EGH 78 by the end of the study period, representing approximately three-quarters of the improvement that would occur if the proposed changes to the OBC were completely accepted. The degree to which the OBC changes will be adopted is largely a function of political lobbying.

[13] The EnerGuide for Homes scale is a linear scale, based on energy consumption of the house as predicted by a HOT2000 simulation. A net-zero house, producing as much energy as it uses on an annual basis, has a rating of 100, by definition. A house that uses as much energy as an R2000 house of the same size has a rating of 80, again by definition. The equation is then EGH = 100 – 20 * (Predicted Annual Energy for Your House) / (Annual Energy for R2000 House). An EGH 90 home is expected to use half as much energy as the R2000 home while an EGH 60 home is expected to use twice as much as the R2000 home. An EGH 73 house would use 1.35 times as much as the R-2000 house. Inverting this means that an improvement from 73 to 80 represents a 26% reduction in energy consumption. More recent information from staff at OMMAH indicates that the current OBC results in homes with an average EGH rating of 76 or even 77. This would reduce estimated savings for EGH 80 further, to less than 17%.

However, there are a number of trends that counteract the thermal improvements in Ontario's construction standards:

- The amount of window area in new houses has increased by up to 20% compared to typical existing homes.[14]

- In both the Southern and Northern service regions, new residential stock floor areas increased by 8% to 10% between the 1980-1993 period and the 1993-2007 period.[15] Recent Union residential surveys have indicated that the increase has now levelled off. Consequently, the average size of newly constructed homes is assumed to remain stable throughout the study period.

- Buildings in both service regions also feature an increase in exterior wall surface area of 5% to 20%.[16] This reflects both the increased floor area and a tendency for homes to include architectural features with more corners and details that diverge from the standard rectangular shapes.

- The Federal and Ontario governments are proposing to phase out incandescent lights by 2012.[17] This change would result in a reduction of internal gains and a corresponding increase in the net space heating load that must be met by furnaces.

The net effect of the above trends is that the improvement in thermal efficiencies is expected to be a much stronger influence than any further increases in house size, window area, etc. The model therefore assumes an approximate 25% reduction in the net space heating load of new homes for the 2012 milestone year, relative to the current average ***existing*** house. Most of this 25% improvement is already incorporated into standard practices for new construction, because of the 2006 OBC revision.

The 25% improvement reflects an improvement in overall performance of the building envelope and the heating equipment. Specific construction changes used to attain the improved performance would vary with each housing design. In general, however, they would be expected to include:

- Condensing furnaces (already mandatory)
- Improved air tightness (to approximately 1.5 ACH at 50 Pa)
- ENERGY STAR® windows
- Wall insulation to an RSI value of 3.5
- Attic insulation to an RSI value of 7
- Floor to ceiling foundation insulation

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[14] ecoENERGY Retrofit database (Ontario). The houses in the database are likely larger than the average in the overall population, but this is expected to be true of both the older and newer homes in the database, so it can be used to give an indication of the rate of increase.

[15] ecoENERGY Retrofit database (Ontario).

[16] ecoENERGY Retrofit database (Ontario).

[17] Natural Resources Canada, Office of Energy Efficiency. *Bulletin on Developing Energy Efficiency Standards for General Service Lighting*, Dec. 2007.

Exhibit 3.2 illustrates how the model assumes new houses built later in the study period will compare with existing houses and with those constructed in the Base Year 2007. The example is based on the space heating load of average single-family dwellings in the Southern Region.

Exhibit 3.2: New Residential Units – Illustration of Efficiency Changes in New Construction Through the Study Period

Exhibit 3.3 summarizes the resulting new net space heating loads for new homes built in the first milestone period.

Exhibit 3.3: New Residential Units – Net Space Heating Load[18] by Dwelling Type and Service Region (MJ/yr. and m^3/yr.)

Segment	Net Space Heating Load (MJ/yr.)		Space Heating UEC (m^3)	
	Southern	Northern	Southern	Northern
Single-Family Detached/ Duplex	46,641	49,920	1,348	1,455
Attached/Row Housing/Tris & Quads	31,250	41,802	903	1,218
Other	22,916	37,838	662	1,103

3.3 "NATURAL" CHANGES TO SPACE HEATING – EXISTING DWELLINGS

In addition to the construction of new buildings, the Reference Case also assumes that a portion of the existing building stock is subject to energy retrofits in each period. To provide a reasonable estimate of the impact of these "naturally" occurring retrofit activities on the net heating loads, the study employed the following steps:

- A bundle of upgrade measures associated with a "typical" retrofit within each dwelling type was defined.
- The rate at which the bundle of measures is introduced into the existing stock of buildings was estimated.

[18] Net space heating load is the space heating load of a building that must be met by the space heating system over a full year. This is equal to the total heat loss through the building envelope minus solar and internal gains.

- The energy impacts of these upgrades were estimated and the resulting overall volumes were compared to the Union forecast volumes for agreement.

The results of this process are summarized in the following sections.

3.3.1 Energy Retrofit and Activity Levels – Existing Dwellings

Exhibit 3.4 presents a summary of the major energy retrofit measures and the reported annual participation rates by dwelling type. The percentages were based on responses to a large national survey and indicate the percentage of all respondents who had the retrofit measure applied to their dwellings in 1995.[19] It is particularly useful in giving the frequency of different retrofit measures relative to each other. Although this study is fairly dated, it can be used as an indicator to show that window and door retrofits are by far the most common. It is anticipated that this trend has not changed significantly in recent years.

Exhibit 3.4: Annual Energy Retrofit Activity by Dwelling Type (%)

Retrofit Measure	Dwelling Type and Participation Rate (%)			
	Single	Row	Apartment	Mobile/Other
Insulation Improvements	4.20	2.40	2.30	4.10
Exterior Doors	5.40	5.90	2.80	5.30
Window Replacements	6.70	7.00	4.10	6.60
Fireplace Improvements	2.90	1.60	1.20	2.70
Heating System Conversions	0.90	0.40	0.10	0.90
Energy Source Conversions	0.90	0.80	0.10	0.90
Heating Equipment Replacements	2.90	2.10	1.00	2.90
Averages	3.41	2.89	1.66	3.34

Source: Home Energy Retrofit Survey – Statistical Report (NRCan, 2000)

3.3.2 Net Impact on Space Heating Loads – Existing Homes

Trial energy simulation runs were undertaken in HOT2000, assuming a variety of combinations of the retrofit measures shown in Exhibit 3.4. The results varied widely, from a 2% to 15% reduction in space heating loads, depending on assumptions related to type and scale of retrofits performed (e.g., the number of windows or doors replaced). For example, a typical post-1980s detached house in the Southern Region in which the only improvement is the addition of a layer of fiberglass batts to the attic would experience a reduction of approximately 2%. A typical pre-1980s detached house in the Northern Region in which the attic insulation is increased to RSI-7 (R-40), all the windows are replaced with ENERGY STAR® windows and the basement walls are insulated up to RSI-4 (R-22) would experience a reduction of approximately 15%.

In the absence of more comprehensive data, this analysis assumes the retrofit participation rates presented in Exhibit 3.4 and assumes that each renovated unit

[19] Natural Resources Canada. *Home Energy Retrofit Survey - Statistical Report*, 2000.

experiences a net space heat reduction of 9%. This reflected a package of activities that included replacing half of the windows with ENERGY STAR® windows (savings of approximately 6% on average) plus one other building envelope retrofit saving 6% in half of the projects.

The development of Ontario's new building codes is expected to play a role in the degree of improvement caused by a retrofit or renovation project, but is expected to be gradual, not dramatic.

3.4 "NATURAL" CHANGES TO ANNUAL APPLIANCE ENERGY USE

Changes in the annual energy consumption of residential appliances and heating equipment result from improvements in the energy efficiency of new models. The gradual penetration of these new, more efficient models into the stock of new and existing residences results in a gradual decrease in the consumption of each type of appliance.

NRCan data[20,21] show that significant improvements occurred in the energy efficiency of new appliances and heating equipment during the late 1980s and mid-1990s. During the post-1997 period, however, the efficiency of new natural gas appliances (clothes dryers and cooking ranges) remained relatively unchanged. Consequently, this Reference Case assumes that, in the absence of new initiatives, further improvements in the efficiency of new appliances will be relatively minor over the forecast period. However, the energy consumption of the stock of natural gas appliances and heating equipment will continue to decrease as the existing stock is replaced over the study period.

Further discussion of assumptions applied to the major natural gas appliance appliances and heating equipment is provided below. The discussion is organized as follows:

- Furnaces
- Domestic Hot Water
- Cooking
- Dryers
- Pool Heaters
- Fireplaces
- Other

3.4.1 Furnaces

Program evaluation work and market surveys undertaken by Union show that there is a trend towards the use of more efficient furnaces in both new construction and replacement markets. As noted previously, 2006 changes to the Ontario Building Code require that high-efficiency furnaces (minimum AFUE of 90%) be installed in new homes.

[20] Natural Resources Canada. *Energy Consumption of Major Household Appliances Shipped in Canada: Trends for 1990-2005*, Dec. 2007.

[21] Natural Resources Canada. *Energy Use Data Handbook*, p. 38-39, 2005.

In addition, NRCan's Office of Energy Efficiency (OEE) is currently in the process of updating the Minimum Energy Performance Standards (MEPS) for residential furnaces; a minimum AFUE of 90% is currently proposed, beginning at the end of 2009.[22]

The above measures will increase the average efficiency of residential natural gas furnaces. This Reference Case assumes that furnace efficiencies improve in accordance with Union's Residential Furnace Efficiency Index, which improves from a current level of 81.7% to 87.9% by 2012. The Reference Case assumes a continuation of this trend to 2017 when the average furnace efficiency will be approximately 92%.

3.4.2 Domestic Hot Water

Exhibit 3.5 summarizes DHW UECs by application for new dwellings. A comparison with the values presented previously for existing dwellings (see Section 2) shows significant reductions for hot water use in dishwashing and clothes washing; however, slightly more modest changes have been assumed for personal consumption.

Factors that will affect DHW energy use include trends towards more efficient water heaters and front loading washers (which use less water) and an improvement in the MEPS for residential dishwashers, proposed to come into effect in 2010.[23]

Exhibit 3.5: Distribution of DHW Energy Use by End Use in New Stock (m^3yr.)

End Use	Energy Use (m^3/yr.)	%
Personal Use	215	36
Dishwashing	138	23
Clothes Washing	153	25
Standby Losses	99	16
Total	604	100%

Note: Any difference in totals is due to rounding.

For existing dwellings, the DHW UEC is assumed to decrease by 0.5% per year based on the estimated impact of the changes described above.

3.4.3 Cooking

Only a modest contribution to reduced natural gas consumption in cooking ranges will come from the gradual penetration of new, more efficient models into the stock of new and existing residences. The efficiency of new units is not expected to improve significantly over the study period. Some change in consumption has been occurring due to changing occupancy per household and changes in occupant behaviour over time.[24] In

[22] Natural Resources Canada, Office of Energy Efficiency. *Proposed Amendment to Canada's Energy Efficiency Regulations for Gas Furnaces*, Jan. 2008.

[23] Natural Resources Canada, Office of Energy Efficiency. *Proposed Regulations for Residential Dishwashers,* Aug. 2007.

[24] Natural Resources Canada, Office of Energy Efficiency. *Energy Consumption of Major Household Appliances Shipped in Canada: Trends for 1990-2005*, 2008.

general, the number of occupants per household has been declining, and people have been cooking fewer large meals at home. These trends were assumed to continue; therefore, this Reference Case assumes that the current gas cooking UEC declines (in a straight line) by 1.6% by the final milestone year.

3.4.4 Dryers

As in the case of cooking ranges, only a modest contribution to reduced natural gas consumption in gas clothes dryers will come from the gradual penetration of new, more efficient models into the stock of new and existing residences. The efficiency of new units is not expected to improve significantly over the study period. Some change in consumption has been occurring due to changing occupancy per household, which has been declining.[25] In addition, the advent of horizontal axis clothes washers with faster spin speeds has been further reducing dryer energy consumption. These trends were assumed to continue; therefore, this Reference Case assumes that the current clothes dryer UEC declines (in a straight line) by 1.8% by the final milestone year.

3.4.5 Pool Heaters

The UEC for pool heaters was assumed to decline over the study period, due to increased natural adoption of insulating pool blankets and solar pool heaters. Penetration of these two technologies is currently approximately 70% (i.e., 30% of heated pools have neither of them).[26] Over the study period, total penetration of the two technologies was assumed to reach 85% (i.e., 15% of heated pools would have neither). Overall UEC would consequently fall by just over 8% over the study period.

3.4.6 Fireplaces

Fireplaces currently have a very wide range of efficiencies, and the average efficiency of units currently sold has not been extensively studied. Based on previous study team experience and industry discussions, it was estimated that the average efficiency of current fireplace stock is approximately 35% to 40%. According to NRCan data, the average efficiency of fireplaces sold as recently as 2003 was just over 45% (nearly two-thirds of sales were between 40% and 49.9% efficient). By 2005, just two years later, the average efficiency had risen to nearly 60% (units with efficiency below 50% had fallen to less than 10% of sales, with the remainder split nearly evenly between units between 50% and 59.9% efficient and those 60% and over). Average efficiency was assumed to continue rising slightly, to just over 60%, and with natural stock turnover, the average efficiency of fireplaces in homes would rise to slightly over 55% by the end of the study period.

3.4.7 Other

In the absence of any new initiatives, other gas uses (spas, barbecues, etc.) were not assumed to change during the study period.

[25] Ibid.

[26] Based on Union Gas residential market survey data.

3.5 APPLIANCE SATURATION TRENDS

The Reference Case assumed that the estimated Base Year natural gas appliance saturation levels remain constant over the study period.

3.6 STOCK GROWTH

The next step in developing the Reference Case involved the development and application of estimated levels of growth in each dwelling type and service region over the study period. The stock growth rates employed are based on those used in Union's most recent load forecast and were derived from data provided by Union's Load Forecasting Group.[27] However, the most recent Union forecast only extends to 2012 and is not broken out by the dwelling types used in this study. Consequently, it was necessary to extrapolate the Union forecast data from 2012 to 2017 and to estimate the growth rates for the individual dwelling types, based on housing stock data from NRCan and housing start data from the Canadian Mortgage and Housing Corporation (CMHC).[28,29]

Exhibit 3.6 presents a summary of the rates employed and Exhibit 3.7 presents the resulting number of units, by year and dwelling type.

Exhibit 3.6: Annual Growth Rates in Period by Dwelling Type and Service Region (%)

	Single/ Duplex	Attached/ Row, etc.	Mobile/ Other
Southern			
2007-2012	1.1%	4.3%	1.1%
2012-2017	1.0%	4.1%	1.0%
Northern			
2007-2012	1.0%	4.0%	1.0%
2012-2017	1.0%	3.9%	1.0%

[27] It is important to note that both future natural gas sales and building stock growth are heavily dependent on prevailing economic conditions.

[28] Natural Resources Canada. *Comprehensive Energy Use Database*, 2005, with the addition of new housing starts data from CMHC; *Housing Now: Ontario*, 2006 and 2007.

[29] Canadian Mortgage and Housing Corporation. *Housing Market Outlook: Canada Edition*, p. 13, 2008.

Exhibit 3.7: Residential Stock, 2007 and 2017 (Number of Units)

Segment	2007 Base Year			2012 Milestone Year			2017 Milestone Year		
	Southern Region	Northern Region	Total	Southern Region	Northern Region	Total	Southern Region	Northern Region	Total
Single-Family Detached/Duplex, Gas Heated	717,861	221,799	939,660	717,861	221,799	939,660	717,861	221,799	939,660
Single-Family Detached/Duplex, Gas Heated (New)				40,364	11,636	52,000	80,436	23,623	104,058
Single-Family Detached/Duplex, Non-Gas Heated	70,997	36,107	107,104	70,997	36,107	107,104	70,997	36,107	107,104
Single-Family Detached/Duplex, Non-Gas Heated (New)				3,992	1,894	5,886	7,955	3,846	11,801
Attached/Row Housing/Tris & Quads	93,131	7,926	101,057	93,131	7,926	101,057	93,131	7,926	101,057
Attached/Row Housing/Tris & Quads (New)				21,869	1,729	23,598	47,154	3,788	50,943
Other	779	617	1,396	779	617	1,396	779	617	1,396
Other (New)				44	32	76	87	66	153
Subtotal	882,768	266,449	1,149,217	949,037	281,740	1,230,777	1,018,401	297,771	1,316,172

Note: Any difference in totals is due to rounding.

3.7 FUEL SHARES

Fuel shares were assumed to remain constant over the study period.

3.8 AVERAGE NATURAL GAS CONSUMPTION PER DWELLING UNIT

Exhibits 3.8 and 3.9 combine the efficiency, saturation and fuel share data presented in the preceding exhibits and show the resulting average natural gas consumption, by end use, for each dwelling type. For milestone years 2012 and 2017, the average figures are based on all the dwellings in each category, including both those existing in the Base Year and those constructed during the study period.

Exhibits 3.8 and 3.9 present the average natural gas consumption per dwelling unit, broken out by dwelling type and end use for the Southern and Northern service regions, respectively.

Exhibit 3.8 Average Natural Gas Consumption per Dwelling Unit in the Southern Service Region (m^3/yr.)

Dwelling Type	Milestone Year	Annual Gas Consumption per Dwelling Unit (m^3/yr.)							
		Total	Space Heating	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use
Single-Family Detached/ Duplex	2007	2,628	1,639	617	108	31	55	97	80
	2012	2,514	1,553	607	95	31	55	93	80
	2017	2,414	1,500	574	86	31	54	89	80
Attached/Row Housing/Tris & Quads	2007	1,792	1,098	442	77	17	31	69	57
	2012	1,652	983	431	67	17	30	67	57
	2017	1,542	903	411	60	17	30	64	57
Other	2007	1,271	805	297	52	12	21	47	39
	2012	1,216	763	292	46	12	20	45	39
	2017	1,167	737	276	41	11	20	43	39
OVERALL AVERAGE	2007	2,539	1,581	599	105	30	52	94	78
	2012	2,409	1,483	586	92	29	52	90	77
	2017	2,293	1,417	551	82	29	51	85	77

Note: Any difference in totals is due to rounding.

Exhibit 3.9 Average Natural Gas Consumption per Dwelling Unit in the Northern Service Region (m^3/yr.)

Dwelling Type	Milestone Year	Annual Gas Consumption per Dwelling Unit (m^3/yr.)							
		Total	Space Heating	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use
Single-Family Detached/ Duplex	2007	2,583	1,722	559	114	14	44	51	80
	2012	2,386	1,572	528	100	14	43	49	80
	2017	2,254	1,490	490	90	14	43	46	80
Attached/Row Housing/Tris & Quads	2007	2,051	1,442	400	81	9	24	36	57
	2012	1,818	1,248	374	70	9	24	35	57
	2017	1,665	1,127	351	63	9	24	33	57
Other	2007	1,714	1,305	269	55	6	16	24	39
	2012	1,578	1,191	254	48	6	16	23	39
	2017	1,492	1,130	236	43	6	16	22	39
TOTAL	2007	2,565	1,713	554	113	14	43	50	79
	2012	2,365	1,560	522	99	14	42	48	79
	2017	2,229	1,475	484	89	13	42	46	79

Note: Any difference in totals is due to rounding.

3.9 SUMMARY OF MODEL RESULTS

This section presents the results of the model runs for the entire study period. The results are measured at the customer's point-of-use and do not include distribution system losses. Model results were compared to Union's forecast of residential consumption assuming no new DSM initiatives. Adjustments were made to the model to produce reasonable agreement, as shown in Section 3.9.1. The model results are presented in three separate exhibits.

Exhibit 3.10 presents the model results for the total Union Service Area. The results are broken out by dwelling type and end use.

Exhibits 3.11 and 3.12 present the same results, broken out by dwelling type and end use for the Southern and Northern service regions, respectively.

Exhibit 3.10: Reference Case Natural Gas Use for the Total Union Service Area, Modelled by End Use and Dwelling Type (1000 m^3/yr.)

Dwelling Type	Milestone Year	Gas Consumption (1000 m^3/yr.)							
		Total	Space Heating	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use
Single-Family Detached/ Duplex	2007	2,739,396	1,737,149	631,184	114,694	28,140	54,695	89,580	83,956
	2012	2,742,719	1,720,850	649,255	106,739	29,457	57,181	90,638	88,599
	2017	2,760,651	1,740,846	643,571	101,281	30,772	59,672	91,260	93,248
Attached/Row Housing/Tris & Quads	2007	183,183	113,708	44,320	7,859	1,684	3,060	6,751	5,801
	2012	207,520	125,057	53,191	8,337	2,059	3,735	7,986	7,155
	2017	235,835	139,827	61,753	9,197	2,496	4,522	9,316	8,725
Other	2007	2,048	1,433	397	74	13	26	51	54
	2012	2,025	1,402	405	69	14	27	52	57
	2017	2,029	1,409	400	65	14	29	52	60
TOTAL	2007	2,924,627	1,852,289	675,900	122,627	29,837	57,781	96,382	89,810
	2012	2,952,264	1,847,308	702,851	115,145	31,530	60,944	98,675	95,811
	2017	2,998,515	1,882,082	705,724	110,544	33,282	64,222	100,628	102,033

Note: Any difference in totals is due to rounding.

Exhibit 3.11: Reference Case Natural Gas Consumption for the Southern Service Region, Modelled by End Use and Dwelling Type (1000 m^3/yr.)

Dwelling Type	Milestone Year	Gas Consumption (1000 m^3/yr.)							
		Total	Space Heating	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use
Single-Family Detached/ Duplex	2007	2,073,275	1,293,067	487,016	85,388	24,584	43,452	76,498	63,270
	2012	2,095,114	1,294,231	505,878	79,526	25,747	45,460	77,444	66,828
	2017	2,117,439	1,315,594	503,646	75,490	26,901	47,455	77,992	70,360
Attached/Row Housing/Tris & Quads	2007	166,930	102,280	41,149	7,215	1,610	2,867	6,463	5,346
	2012	189,964	113,004	49,577	7,660	1,969	3,503	7,650	6,601
	2017	216,330	126,627	57,642	8,455	2,386	4,241	8,926	8,053
Other	2007	990	627	231	41	9	16	36	30
	2012	1,000	628	240	38	9	17	37	32
	2017	1,011	638	239	36	10	18	37	33
TOTAL	2007	2,241,195	1,395,974	528,396	92,643	26,203	46,335	82,997	68,646
	2012	2,286,078	1,407,863	555,695	87,224	27,725	48,980	85,131	73,461
	2017	2,334,780	1,442,859	561,527	83,981	29,297	51,714	86,955	78,446

Note: Any difference in totals is due to rounding.

Exhibit 3.12: Reference Case Natural Gas Consumption for the Northern Service Region, Modelled by End Use and Dwelling Type (1000 m^3/yr.)

Dwelling Type	Milestone Year	Gas Consumption (1000 m^3/yr.)							
		Total	Space Heating	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use
Single-Family Detached/ Duplex	2007	666,121	444,082	144,168	29,306	3,555	11,243	13,082	20,685
	2012	647,605	426,619	143,377	27,213	3,710	11,721	13,194	21,771
	2017	643,212	425,252	139,925	25,791	3,871	12,217	13,268	22,888
Attached/Row Housing/Tris & Quads	2007	16,254	11,428	3,171	645	74	193	288	455
	2012	17,557	12,052	3,614	677	90	233	336	554
	2017	19,505	13,200	4,111	742	110	280	390	672
Other	2007	1,057	805	166	34	4	10	15	24
	2012	1,024	774	165	31	4	11	15	25
	2017	1,018	771	161	30	4	11	15	26
TOTAL	2007	683,432	456,315	147,505	29,984	3,634	11,446	13,385	21,164
	2012	666,186	439,445	147,157	27,921	3,805	11,964	13,545	22,350
	2017	663,736	439,223	144,197	26,562	3,985	12,508	13,673	23,587

Note: Any difference in totals is due to rounding.

3.9.1 Comparison with Union Load Forecast

This section presents a comparison of the model results with Union data, for the Base Year and for the two milestones in the 10-year period being evaluated. The Union forecast for 2012 was adjusted to exclude any new DSM activity. The 2017 consumption values attributed to Union are extrapolations based on the same growth rates employed between 2007 and 2012.

The deviation between the model results and the Union forecasts is very minimal in 2012, with an overall deviation of 0.1% and a difference of 0.4% in the Northern service territory. The variation is somewhat larger in the 2017 milestone, with the model results somewhat under-predicting the Union forecast in general. The overall deviation here is 2.4% and the maximum difference, seen in the Southern service territory, is about 3%.

The model is based on the assumptions of growth and improvement in the stock of housing and appliances that were best supported by available data, and the forecast is based on econometric modelling. The deviations quoted above represent the best agreement that could be achieved between the two. Indeed, it is remarkable that two independent modelling approaches, based on entirely different methodologies, agree as closely as they do.

3.9.2 Interpretation of Results

Selected highlights of the information presented in Chapter 3 are presented below.

Dwelling Type

The rate of growth in Ontario attached housing is approximately three times the rate of growth in detached housing. As a result, although attached housing accounts for only 6%

of existing housing, it is estimated that it will account for close to 30% of new housing during the study period. (These percentages do not include apartments, which are analyzed under the commercial sector.)

End Use

The division of residential gas consumption by end use is expected to be relatively constant over the study period, with a slight decrease in the proportion used for space heating, due primarily to improved building envelopes in new dwellings and to the increasing dominance of condensing furnaces.

Service Region

The proportion of residential natural gas consumption by region is expected to remain relatively constant over the study period.

Characteristics of New Housing

The 2006 Ontario Building Code revision is currently estimated to result in new dwellings with EnerGuide ratings of approximately 76 to 77. This is a substantial improvement over the pre-2006 new houses, which had average EnerGuide ratings of approximately 73. As a result, the potential improvements available in new housing are reduced, and the diminishing returns will tend to make further efficiency gains from DSM programs more challenging.

Equipment and Appliances

Union Gas has been successful in reaching over 50% penetration of condensing furnaces among its residential customers. Next year, the standard will require a minimum efficiency of 90% for residential furnaces. The efficiency of new gas fireplaces is also improving rapidly: the average efficiency of gas fireplaces being sold is now approximately 60%, according to NRCan statistics. This is a dramatic improvement over the units currently installed, which average below 40% efficiency. Opportunities for DSM programs affecting furnaces and fireplaces will be substantially reduced going forward.

4. ENERGY-EFFICIENCY MEASURES

4.1 INTRODUCTION

This section identifies and assesses the financial and economic attractiveness of the selected energy-efficiency measures for the Residential sector. The discussion is organized and presented as follows:

- Methodology
- Summary of energy-efficiency results
- Description of energy-efficiency technologies and measures.

4.2 METHODOLOGY

The following steps were employed to assess the energy-efficiency measures:

- Select candidate energy-efficiency measures
- Establish technical performance for each option within a range of applicable load sizes and/or service region conditions (e.g., degree days)
- Establish the capital, installation and operating costs for each option
- Calculate the simple payback from the customer's perspective
- Calculate the measure total resource cost (measure TRC)
- Calculate the benefit/cost ratio

Step 1: Select Candidate Measures

The candidate measures were selected in close collaboration with Union personnel based on a combination of a literature review and the previous experience of the consultants and Union personnel. The selected measures are considered to be technically proven and commercially available, even if only at an early stage of market entry.[30] Technology costs, which will be addressed in this section, were not a factor in the initial selection of candidate technologies.

Step 2: Establish Technical Performance

Information on the performance improvements provided by each measure was compiled from available secondary sources, including the experience and on-going research work of study team members. As applicable, the energy impacts of the measures are reported for both natural gas and electricity.

[30] During completion of this study step, it was decided that a few of the originally selected measures were not feasible. They are identified in the text.

Step 3: Establish Capital, Installation and Operating Costs for Each Measure

Information on the cost of implementing each measure was also compiled from secondary sources, including the experience and on-going research work of study team members. As applicable, both the incremental and full cost of each measure was estimated.

The incremental cost is applicable when a measure is installed in a new facility, or is replacing equipment that is at the end of its useful life in an existing facility. In this case, incremental cost is defined as the difference between the energy-efficiency measure and the "baseline" technology. The full cost is applicable when an operating piece of equipment is replaced with a more efficient model prior to the end of its useful life.

In both cases, the costs and savings are annualized, based on the number of years of equipment life and the discount rate, which for this study is 10%. The costs incorporate applicable changes in annual equipment O&M costs and all cost are expressed in constant (2008) dollars.

Step 4: Calculate Simple Payback

The simple payback is generated to show the customer's financial perspective. Simple payback is "a measure of the length of time required for the cumulative savings from a project to recover its initial investment cost and other accrued costs, without taking into account the time value of money. The simple payback period is usually measured from the service date of the project."[31] The cost of the measure (incremental or full, as appropriate) is divided by the expected annual savings. The answer is given in years**.**

The following equation illustrates how this calculation is applied to a situation where an upgrade has a higher upfront cost than the baseline technology, but lower ongoing operating costs:

$$\text{Payback}_{\text{(years)}} = (\text{Cost}_{\text{upgrade}} - \text{Cost}_{\text{base}})/(\text{Ann}_{\text{base}} - \text{Ann}_{\text{upgrade}})$$

where, $\text{Cost}_{\text{upgrade}}$ = initial capital cost of the upgrade measure ($)
$\text{Cost}_{\text{base}}$ = initial capital cost of the baseline measure ($)
$\text{Ann}_{\text{upgrade}}$ = ongoing operating cost of the upgrade ($/yr.)
Ann_{base} = ongoing operating cost of the baseline measure ($/yr.)

Step 5: Calculate the Measure Total Resource Cost (TRC)

The measure TRC calculates the net present value of energy and water savings that result from an investment in an efficiency measure. The measure TRC is equal to its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy and equipment O&M costs. This calculation includes, among others, the following inputs: the avoided natural gas, electricity and water supply costs,the life of the technology and the selected discount rate, which in this analysis has been set at 10%.

[31] Fuller, S. K. and Petersen, S. R. *Life Cycle Costing Manual for the Federal Energy Management Program*, National Institute of Standards and Technology Handbook 135, 1995 Edition, Washington, DC.

A technology or measure with a positive TRC value is included in subsequent phases of the analysis, which consists of the economic and achievable potential scenarios. A measure with a negative TRC value is not economically attractive and is therefore not included in subsequent stages of the analysis.

It should be noted that the measure TRC provides an initial screen of the technical options. Considerations such as program delivery costs, free riders and incentives are incorporated in later detailed program design stages, which are beyond the scope of this study.

Step 6: Calculate Benefit/Cost Ratio

The measure benefit/cost ratio indicates the relative attractiveness of the measures. If a measure has a benefit/cost ratio in excess of 1.0, it means that the measure's benefits outweigh its costs. Such a measure would be included in subsequent stages of the analysis. A measure with a benefit/cost ratio that is well in excess of one (e.g., 3.0) is particularly attractive. Conversely, if a measure has a benefit/cost ratio of less than 1.0, its costs outweigh its benefits. Such a measure would not be included in subsequent stages of the analysis.

4.2.1 Energy Costs

The financial and economic results that are presented in this section are based on the following:

- Avoided supply cost of natural gas
- Avoided supply cost of electricity and water
- Customer energy prices.

A brief discussion of each is provided below.

Avoided Supply Cost of Natural Gas

Natural gas avoided supply costs were provided by Union. The data provided were segmented into baseload and weather-sensitive rates and their resulting NPVs (Net Present Values). The rates were forecast for a 30-year timespan and represent Union's 2008 avoided costs. These costs are updated on an annual basis, as prescribed by the Ontario Energy Board (OEB). The same avoided costs are used for Union's entire service region.

A GHG adder was added to the raw avoided supply costs to account for carbon dioxide emissions resulting from natural gas consumption. A cost of \$15/tonne CO_2e (per tonne of CO_2 equivalent) is employed until 2012 and the price is increased to \$20 /tonne CO_2e starting in 2013. An emissions coefficient of 0.001903 tonnes CO_2e/m^3 (1903 g CO_2e/m^3) is used in this analysis.[32] The resulting avoided supply costs for natural gas are shown in Exhibit 4.1.

[32] Based on emission factors and Global Warming Potentials (GWPs) presented in Environment Canada, National Inventory Report (1990-2005): Greenhouse Gas Sources and Sinks in Canada," p. 23 and 583, April 2007.

Exhibit 4.1: Union Gas 2008 Avoided Supply Costs (Natural Gas)

Year	Baseload		Weather Sensitive	
	Gas Rates ($\$/m^3$)	NPV ($\$/m^3$)	Gas Rates ($\$/m^3$)	NPV ($\$/m^3$)
1	0.39898	0.39898	0.40143	0.40143
2	0.38189	0.74614	0.38823	0.75436
3	0.36510	1.04787	0.36231	1.05378
4	0.37148	1.32698	0.36864	1.33075
5	0.37799	1.58515	0.37510	1.58694
6	0.39425	1.82995	0.39130	1.82991
7	0.40101	2.05631	0.39800	2.05457
8	0.40790	2.26562	0.40483	2.26231
9	0.41492	2.45919	0.41179	2.45442
10	0.42207	2.63818	0.41889	2.63207
11	0.42936	2.80372	0.42611	2.79635
12	0.43678	2.95681	0.43348	2.94828
13	0.44435	3.09839	0.44098	3.08879
14	0.45206	3.22934	0.44863	3.21874
15	0.45992	3.35045	0.45642	3.33893
16	0.46793	3.46247	0.46436	3.45010
17	0.47608	3.56608	0.47245	3.55292
18	0.48440	3.66191	0.48070	3.64802
19	0.49287	3.75056	0.48910	3.73599
20	0.50150	3.83256	0.49766	3.81736
21	0.51030	3.90841	0.50639	3.89263
22	0.51927	3.97858	0.51528	3.96226
23	0.52840	4.04349	0.52433	4.02668
24	0.53771	4.10354	0.53357	4.08626
25	0.54719	4.15910	0.54297	4.14139
26	0.55686	4.21049	0.55256	4.19239
27	0.56671	4.25804	0.56232	4.23957
28	0.57674	4.30204	0.57228	4.28322
29	0.58697	4.34274	0.58242	4.32361
30	0.59739	4.38040	0.59275	4.36098

Note: *Union's avoided costs have been modified by the addition of a GHG adder*

Avoided Supply Cost of Electricity and Water

The avoided supply costs of electricity and water used in this analysis were also provided by Union and are shown in Exhibit 4.2. A GHG adder was also added to the electricity costs to account for average CO_2 emissions from electricity production in Ontario. A method similar to that described for the natural gas avoided costs was used. An emissions coefficient of 0.000220 tonnes CO_2e/kWh (220 g CO_2e/kWh) is used in this analysis.[33] The same electricity avoided cost values were used for both service regions.

[33] Based on Ontario emission factors presented in Environment Canada, National Inventory Report (1990-2005): Greenhouse Gas Sources and Sinks in Canada," p. 521, April 2007.

Exhibit 4.2: Union Gas 2008 Avoided Supply Costs (Electricity and Water)

Year	Water Rates		Electricity Rates	
	Rates ($/1000 L)	NPV ($/1000 L)	Rates ($/kWh)	NPV ($/kWh)
1	1.68504	1.68504	0.08032	0.08032
2	1.71705	3.24599	0.08177	0.15465
3	1.74967	4.69200	0.08324	0.22345
4	1.78292	6.03154	0.08474	0.28712
5	1.81679	7.27243	0.08627	0.34604
6	1.85131	8.42195	0.08922	0.40144
7	1.88649	9.48682	0.09081	0.45271
8	1.92233	10.47328	0.09243	0.50014
9	1.95886	11.38710	0.09408	0.54403
10	1.99607	12.23363	0.09577	0.58464
11	2.03400	13.01783	0.09748	0.62223
12	2.07265	13.74428	0.09923	0.65701
13	2.11203	14.41723	0.10101	0.68919
14	2.15215	15.04064	0.10282	0.71897
15	2.19304	15.61813	0.10467	0.74654
16	2.23471	16.15311	0.10655	0.77204
17	2.27717	16.64869	0.10847	0.79565
18	2.32044	17.10777	0.11042	0.81750
19	2.36453	17.53305	0.11242	0.83772
20	2.40945	17.92702	0.11445	0.85643
21	2.45523	18.29197	0.11652	0.87375
22	2.50188	18.63005	0.11862	0.88978
23	2.54942	18.94324	0.12077	0.90461
24	2.59786	19.23336	0.12296	0.91835
25	2.64722	19.50212	0.12519	0.93106
26	2.69751	19.75109	0.12747	0.94282
27	2.74877	19.98173	0.12978	0.95371
28	2.80099	20.19538	0.13214	0.96379
29	2.85421	20.39330	0.13455	0.97312
30	2.90844	20.57665	0.13700	0.98176

Note: *Union's avoided costs for electricity have been modified by the addition of a GHG adder*
1 kWh=3.6 MJ; 1 GJ=1000 MJ

Customer Resource Costs

The customer resource costs used in this analysis are presented in Exhibit 4.3. These values are used in the calculation of customer payback periods that are presented in later sections of this report. In the case of both electricity and natural gas, the prices shown are based on July 2008 rate schedules.

Exhibit 4.3: Customer Resource Costs

Service Region	**Nat. Gas[34] ($/m³)**	**Electricity[35] ($/kWh)**	**Water[36] ($/1000L)**
Northern	0.540	0.095	1.675
Southern	0.458	0.098	1.650

4.3 SUMMARY OF ENERGY-EFFICIENCY SCREENING RESULTS

A summary of the screening results for the energy-efficiency measures is presented in Exhibits 4.4 and 4.5. Due to the number of measures assessed, the following exhibits only show results for those options that pass the screen. The following measures did not pass the economic screen:

Building Envelope:
- Retrofit Windows with Low-E Films
- Air Leakage Sealing
- Attic Insulation
- Wall Insulation
- Foundation Insulation
- Crawlspace Insulation

New Building Design:
- High-Performance Homes (EGH 80/R2000/ENERGY STAR®)
- Under-Slab Insulation

Space Heating and Ventilation Equipment:
- Condensing Furnaces
- Condensing Boilers
- High-Efficiency Heat Recovery Ventilators (HRVs)
- Integrated Mechanical System (Heating and DHW)
- Gas-Fired Heat Pumps
- Duct Sealing
- Furnace Tune-Ups
- Furnace Filter Alarms

Domestic Hot Water (DHW):
- DHW Heat Traps
- Condensing Water Heaters
- Wastewater Heat Recovery Systems
- Solar Hot Water Systems (DHW)

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[34] Natural gas rates are approximate estimates based on Union rates (as of July 1, 2008) in each service region and average natural gas consumption levels in each service region. Rates exclude current $17.00 monthly charge.

[35] Customer electricity rates are based on electricity rates charged by EnWin (utility which services Windsor) and North Bay Hydro (according to their websites, as of July 2008). Fixed customer charges are not included.

[36] Water rates based on water and wastewater rates in several municipalities in both service regions. A weighted average is obtained based on the populations in these municipalities and an assumed annual water consumption of 300,000 L. Fixed charges are not included.

Major Appliances:

- High-Efficiency Gas Ranges
- High-Efficiency Gas Dryers

Pool Heaters:

- High-Efficiency Pool Heaters

The calculations for all of the measures, including the options that did not pass the screen, are contained in Appendix A.

Exhibit 4.4: Summary of Measure TRC Screening Results Residential Sector Energy-efficiency Options – Southern Region

Measure	Measure Description	Full/Incr	Simple Payback (Years)	Measure TRC ($)	Benefit/Cost Ratio
Air Sealing and Insulation (Old Homes)	Single Detached (Old Existing)	Full	7.1	$335	1.16
High-Performance Windows (ENERGY STAR®)	Single Detached (Existing)	Incr.	5.7	$234	1.47
High-Performance Windows (ENERGY STAR®)	Attached (Existing)	Incr.	5.0	$246	1.70
High-Performance Windows (ENERGY STAR®)	Single Detached (New)	Incr.	3.2	$488	2.63
High-Performance Windows (ENERGY STAR®)	Attached (New)	Incr.	2.7	$440	3.20
Super High-Performance Windows	Single Detached (Existing)	Incr.	8.2	$29	1.03
Super High-Performance Windows	Attached (Existing)	Incr.	7.4	$94	1.13
Super High-Performance Windows	Single Detached (New)	Incr.	5.0	$424	1.71
Super High-Performance Windows	Attached (New)	Incr.	4.3	$400	2.00
Programmable Thermostats	Single Detached (Existing)	Full	0.5	$820	13.61
Programmable Thermostats	Attached (Existing)	Full	0.8	$531	9.16
Programmable Thermostats	Single Detached (New)	Incr.	0.7	$628	10.66
Programmable Thermostats	Attached (New)	Incr.	1.0	$402	7.19
High-Efficiency Fireplaces	Single Detached (Existing)	Incr.	3.3	$86	1.86
High-Efficiency Fireplaces	Attached (Existing)	Incr.	4.6	$33	1.33
High-Efficiency Fireplaces	Single Detached (New)	Incr.	4.6	$36	1.36
Solar Pre-Heated Make-Up Air	Single Detached (Existing)	Full	6.7	$74	1.06
Ultra Low-Flow Showerheads	Single Detached (Existing)	Full	0.2	$570	39.01
Ultra Low-Flow Showerheads	Attached (Existing)	Full	0.2	$419	28.92
Ultra Low-Flow Showerheads	Single Detached (New)	Full	0.2	$551	37.71
Ultra Low-Flow Showerheads	Attached (New)	Full	0.2	$405	27.99
Hot Water Pipe Insulation	Single Detached (Existing)	Full	0.1	$65	66.30
Hot Water Pipe Insulation	Attached (Existing)	Full	0.1	$46	47.45
DHW Temperature Reduction	Single Detached (Existing)	Full	0.0	$37	N/A
DHW Temperature Reduction	Attached (Existing)	Full	0.0	$27	N/A
Tankless Gas-Fired DHW	Single Detached (Existing)	Incr.	5.9	$134	1.19
Tankless Gas-Fired DHW	Single Detached (New)	Incr.	6.4	$76	1.11
DHW Recirculation Systems	Single Detached (Existing)	Full	6.9	$39	1.08
DHW Recirculation Systems	Single Detached (New)	Full	7.4	$12	1.02
Efficient Dishwashers	Single Detached (Existing)	Incr.	1.2	$195	4.90
Efficient Dishwashers	Attached (Existing)	Incr.	1.7	$132	3.65
Efficient Dishwashers	Single Detached (New)	Incr.	1.3	$182	4.63
Efficient Dishwashers	Attached (New)	Incr.	1.8	$123	3.45

Measure	Measure Description	Full/Incr	Simple Payback (Years)	Measure TRC ($)	Benefit/Cost Ratio
Efficient Clothes Washers	Single Detached (Existing)	Incr.	3.5	$524	2.05
Efficient Clothes Washers	Attached (Existing)	Incr.	4.6	$303	1.61
Efficient Clothes Washers	Single Detached (New)	Incr.	3.6	$495	1.99
Efficient Clothes Washers	Attached (New)	Incr.	4.7	$283	1.57
Swimming Pool Covers	Single Detached (Existing)	Full	2.8	$916	1.76
Swimming Pool Covers	Attached (Existing)	Full	3.9	$315	1.26
Swimming Pool Covers	Single Detached (New)	Full	2.9	$828	1.69
Swimming Pool Covers	Attached (New)	Full	4.0	$252	1.21
Solar Pool Heaters	Single Detached (Existing)	Full	1.7	$5,824	4.15
Solar Pool Heaters	Attached (Existing)	Full	2.4	$3,642	2.97
Solar Pool Heaters	Single Detached (New)	Full	1.8	$5,505	3.98
Solar Pool Heaters	Attached (New)	Full	2.5	$3,414	2.85

Exhibit 4.5: Summary of Measure TRC Screening Results Residential Sector Energy-efficiency Options – Northern Region

Measure	Measure Description	Full/Incr	Simple Payback (Years)	Measure TRC ($)	Benefit/Cost Ratio
Air Sealing and Insulation (Old Homes)	Single Detached (Old Existing)	Full	6.5	$562	1.27
Air Sealing and Insulation (Old Homes)	Attached (Old Existing)	Full	6.7	$377	1.21
High-Performance Windows (ENERGY STAR®)	Single Detached (Existing)	Incr.	5.6	$247	1.49
High-Performance Windows (ENERGY STAR®)	Attached (Existing)	Incr.	4.8	$256	1.73
High-Performance Windows (ENERGY STAR®)	Single Detached (New)	Incr.	3.4	$451	2.50
High-Performance Windows (ENERGY STAR®)	Attached (New)	Incr.	2.8	$405	3.03
Super High-Performance Windows	Single Detached (Existing)	Incr.	7.5	$117	1.12
Super High-Performance Windows	Attached (Existing)	Incr.	6.4	$210	1.30
Super High-Performance Windows	Single Detached (New)	Incr.	4.7	$485	1.81
Super High-Performance Windows	Attached (New)	Incr.	3.6	$541	2.35
Programmable Thermostats	Single Detached (Existing)	Full	0.5	$908	14.96
Programmable Thermostats	Attached (Existing)	Full	0.6	$736	12.33
Programmable Thermostats	Single Detached (New)	Incr.	0.6	$675	11.39
Programmable Thermostats	Attached (New)	Incr.	0.7	$541	9.33
High-Efficiency Fireplaces	Single Detached (Existing)	Incr.	3.0	$106	2.06
High-Efficiency Fireplaces	Attached (Existing)	Incr.	4.2	$48	1.48
High-Efficiency Fireplaces	Single Detached (New)	Incr.	4.1	$51	1.51
High-Efficiency Fireplaces	Attached (New)	Incr.	5.7	$8	1.08
Solar Pre-Heated Make-Up Air	Single Detached (Existing)	Full	6.0	$227	1.17
Ultra Low-Flow Showerheads	Single Detached (Existing)	Full	0.2	$566	38.72
Ultra Low-Flow Showerheads	Attached (Existing)	Full	0.2	$416	28.71
Ultra Low-Flow Showerheads	Single Detached (New)	Full	0.2	$532	36.48
Ultra Low-Flow Showerheads	Attached (New)	Full	0.2	$392	27.11
Hot Water Pipe Insulation	Single Detached (Existing)	Full	0.1	$64	65.27
Hot Water Pipe Insulation	Attached (Existing)	Full	0.1	$46	46.71
DHW Temperature Reduction	Single Detached (Existing)	Full	0.0	$37	N/A

Measure	**Measure Description**	**Full/Incr**	**Simple Payback (Years)**	**Measure TRC ($)**	**Benefit/Cost Ratio**
DHW Temperature Reduction	Attached (Existing)	Full	0.0	$26	N/A
Tankless Gas-Fired DHW	Single Detached (Existing)	Incr.	6.0	$121	1.17
Tankless Gas-Fired DHW	Single Detached (New)	Incr.	6.9	$20	1.03
DHW Recirculation Systems	Single Detached (Existing)	Full	7.0	$33	1.07
Efficient Dishwashers	Single Detached (Existing)	Incr.	1.3	$192	4.84
Efficient Dishwashers	Attached (Existing)	Incr.	1.7	$130	3.60
Efficient Dishwashers	Single Detached (New)	Incr.	1.4	$169	4.37
Efficient Dishwashers	Attached (New)	Incr.	1.9	$113	3.27
Efficient Clothes Washers	Single Detached (Existing)	Incr.	3.5	$516	2.03
Efficient Clothes Washers	Attached (Existing)	Incr.	4.6	$298	1.60
Efficient Clothes Washers	Single Detached (New)	Incr.	3.7	$468	1.94
Efficient Clothes Washers	Attached (New)	Incr.	4.9	$264	1.53
Swimming Pool Covers	Single Detached (Existing)	Full	2.5	$1,152	1.96
Swimming Pool Covers	Attached (Existing)	Full	3.5	$484	1.40
Swimming Pool Covers	Single Detached (New)	Full	2.6	$1,054	1.88
Swimming Pool Covers	Attached (New)	Full	3.6	$413	1.34
Solar Pool Heaters	Single Detached (Existing)	Full	1.5	$6,679	4.61
Solar Pool Heaters	Attached (Existing)	Full	2.1	$4,254	3.30
Solar Pool Heaters	Single Detached (New)	Full	1.6	$6,323	4.42
Solar Pool Heaters	Attached (New)	Full	2.2	$4,000	3.16

4.4 DESCRIPTION OF ENERGY-EFFICIENCY TECHNOLOGIES AND MEASURES

This section provides a brief description of each of the energy-efficiency technologies and measures that are included in this study, as listed in Exhibit 4.6.

Exhibit 4.6: Energy-efficiency Technologies and Measures - Residential Sector

Building Envelope
- High-Performance (ENERGY STAR®) Windows
- Super High-Performance Windows
- Retrofit Windows with Low-E Films
- Air Leakage Sealing
- Attic Insulation
- Wall Insulation
- Foundation Insulation
- Crawlspace Insulation
- Vacuum Panel Insulation
- Air Leakage Sealing and Insulation (Old Homes)

New Building Design
- High-Performance Homes (EGH 80) R2000/ENERGY STAR®)
- Under-Slab Insulation

Space Heating and Ventilation Equipment
- Condensing Furnaces
- Condensing Boilers
- High-Efficiency Heat Recovery Ventilators (HRVs)
- Programmable Thermostats
- Integrated Mechanical System (Heating and DHW)
- Gas-Fired Heat Pumps
- Duct Sealing
- Furnace Tune-Ups
- Furnace Filter Alarms
- EnerGuide Natural Gas Fireplaces
- Solar Pre-Heated Make-Up Air (e.g., SolarWall®)

Domestic Hot Water
- Ultra Low-Flow Showerheads
- Hot Water Pipe Insulation
- DHW Heat Trap
- DHW Temperature Reduction
- Water Heater Timers
- Condensing Water Heaters
- Tankless Gas-Fired DHW
- Wastewater Heat Recovery
- Solar Hot Water Systems (DHW)
- DHW Recirculation Systems (e.g. Metlund D'MAND®)

Major Appliances
- High-Efficiency Gas Ranges
- High-Efficiency Gas Dryers
- DHW Savings from Efficient Dishwashers
- DHW and Dryer Savings from Efficient Clothes Washers

Pool Heaters
- Insulating Swimming Pool Covers
- High-Efficiency Pool Heaters
- Solar Pool Heaters

4.4.1 Building Envelope

Building envelope measures improve the thermal performance of the building's walls, roof and/or windows. These measures also provide significant co-benefits, such as increased occupant comfort, improved resale value, etc. Ten building envelope energy-efficiency upgrade options were identified and assessed:[37]

- High-performance (ENERGY STAR®) Windows
- Super High-performance Windows
- Retrofit Windows with Low-E Films

[37] All input assumptions that are not otherwise referenced are from the Marbek internal database.

- Air Leakage Sealing
- Attic Insulation
- Wall Insulation
- Foundation Insulation
- Crawlspace Insulation
- Vacuum Panel Insulation
- Air Leakage Sealing and Insulation (Old Homes).

High-Performance (ENERGY STAR®) Windows

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing and new
Costs	$43/m^2 incremental cost in existing • $500 in existing single detached • $350 in existing attached $21.50/m^2 incremental cost in new • $300 in new single detached • $200 in new attached
Savings	Southern: 7.5%-12% of HVAC energy Northern: 7%-9% of HVAC energy
Useful Life	30 years

High-performance windows have an RSI value of 0.5 (R-2.8) or higher, compared to standard double glazed windows, which are clear with no gas filling and typically have an RSI value of 0.34 (R-1.9) or less. High-performance windows are double glazed with a ½"-inch air space. They incorporate a number of additional energy-saving features, including low-e (soft coating), insulating spacers, argon fill, and low conductivity frames (a mix of sliders, hinged and picture). The more efficient windows reduce heat loss through the window by 25% or more, compared to the average low- or mid-efficiency replacement windows, depending on dwelling type and region. High-performance windows also provide occupant co-benefits, such as reduced interior noise, reduced air leakage, greater thermal comfort and fewer condensation problems.

This analysis employs an incremental cost of $43/m^2 ($4/ft^2) of window area to renovate an existing attached or detached dwelling to high-performance windows as opposed to standard windows. The comparable cost in a new home is assumed to be 50% of those for existing homes.[38, 39] The total costs shown above assume that half of the window area in an average existing home is replaced. The corresponding savings range from about 7.5% to 12% of space heating energy in the Southern region and 7% to 9% of space heating

[38] Cost data from personal communications with window distributors and installers. High-performance windows are cheaper in new homes due to different purchasing patterns. Most windows used for new homes are purchased by tract builders at wholesale prices. In the wholesale market, the incremental cost between standard windows and ENERGY STAR® level performance is modest. In contrast, most windows purchased for retrofit, either by homeowners or by retrofit contractors, are priced at retail. In the retail market, there is a substantial mark-up applied to the increment between standard and ENERGY STAR® level windows. Competitive pressures may reduce this mark-up with time in some markets.

[39] New home cost is more than half of existing home cost due to a higher average window area in new homes.

energy in the Northern region. Savings also include similar percentages of air conditioning and ventilation fan energy.[40]

If the upgrade is chosen as part of a new construction, the incremental cost per unit window area is about 50% lower and the potential savings are higher (as a percentage of space heating use) because new homes tend to have more and larger windows. Since the other building shell components are better in a new home, windows account for a larger fraction of the heat loss than they do in an older home. Therefore, they represent a larger proportion of new home heating energy consumption. The product lifetime for windows is approximately 30 years.[41]

Super High-Performance Windows

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing and new
Costs	$86/m^2 incremental cost in existing • $950 in existing single detached • $700 in existing attached $43/m^2 incremental cost in new • $600 in new single detached • $400 in new attached
Savings	Southern: 10%-15% of HVAC energy Northern: 10%-14% of HVAC energy
Useful Life	30 years

In addition to low-e coating, argon fill, and insulating spacers, super-high performance windows incorporate features such as triple glazing, transparent insulating films or fibreglass frames and their equivalent R-values range from RSI-1.0 (R-5.7) to RSI-1.9 (R-11). These windows are approximately twice the cost of the high-performance windows; incremental costs would be approximately $86 per square meter; the costs for new homes are assumed to be 50% of those for existing homes. The total costs shown above assume that half of the window area in an average existing home is replaced. In this situation, the energy savings for the entire residential HVAC system would range from 10% to 15% in the Southern service region and 10% to 14% in the Northern service region.[42]

Although triple-glazed units are considerably heavier and can sometimes present fastening issues for existing vinyl window frame extrusions, this does not cause the installation cost to increase.[43] A measure life of 30 years is assumed in this analysis.

[40] Based on HOT2000 models of both attached and detached homes in both service regions.

[41] Personal communications with window distributors and installers.

[42] Based on HOT2000 models of both attached and detached homes in both service regions.

[43] Personal communications with window distributors and installers.

Retrofit Windows with Low-E Films

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing
Costs	$75/m^2 full cost in existing • $800 in existing single detached • $500 in existing attached
Savings	1.5% of space heating energy 12% of space cooling energy
Useful Life	20 years

Improving the energy performance of existing windows can be achieved by installing low-e films on the interior surface of the glass. These films are often coated with very thin layers of certain metals that are nearly clear. Low-e films improve the energy performance of windows by greatly reducing the amount of non-visible radiation that is absorbed and transmitted through the window. In the summer, heat is kept out, and in the winter, heat is kept in. In addition, these films improve the thermal resistance (i.e., insulation value) of windows.

Several brands of low-e window films are available, including Solar Gard (Bekaert Specialty Films) and Llumar and Vista (both CPFilms Inc.). These films have emissivities of about 0.33 and solar heat gain coefficients around 0.25. In addition, they improve window insulation by up to RSI-0.10 (R-0.59).[44] Based on these specifications, it is estimated that low-e films can reduce space heating requirements by about 1.5% and space cooling energy consumption by about 12%.[45] In an average retrofit situation where they are installed on half of the windows in a home, the approximate installed cost of low-e films is $75/m^2 ($7/ft^2) or $800 in an average single detached dwelling and $500 in an average attached dwelling. Although the manufacturers often offer limited lifetime warranties, they are estimated to have practical lifetimes of about 20 years.[46]

As added benefits, these films reduce glare and fading and make windows more secure by preventing them from shattering.

[44] Based on personal communication with Solar Gard representative. A double-glazed window was modeled (using WINDOW 5.2) before and after the application of their low-e film to estimate the change in insulation value.

[45] Based on HOT2000 models of both attached and detached homes in both service regions.

[46] Cost and lifetime data based on personal communications with several window film distributors.

Air Leakage Sealing

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing and new
Costs	Single Detached • $1,800 full cost in existing • $1,200 full cost in new Attached • $1,400 full cost in existing • $1,000 full cost in new $20 annual equipment O&M cost in both new and existing
Savings	11% of HVAC energy
Useful Life	25 years

Air leakage sealing of building envelopes includes completion of a blower door test to quantify leakage levels and to identify the location of air leaks. Generally, major leakage occurs at window-to-wall interfaces, around doors (especially patio doors), through electrical and plumbing penetrations, and at the top of foundation walls. Installation of sealant and gaskets are generally accepted methods for reducing air leakage in buildings. Other sources of air leaks include pot lights, wall-to-floor interfaces (i.e., top and bottom of baseboards), and bathroom and kitchen exhaust piping.

Air sealing also provides important co-benefits, including reduced drafts, increased occupant comfort and greater control over ventilation capability. In addition, reduced air leakage around windows and attic penetrations eliminates one of the key contributors to water ingress into exterior envelope assemblies.

In existing dwellings, a comprehensive job can typically reduce air leakage by 30% to 40%, which results in average space heating savings of about 11%. Electricity savings from air conditioning, if applicable, and ventilation fans would be approximately the same percentage. The cost of air leakage sealing is approximately $1,800 per existing single-family dwelling, if undertaken by an air-sealing contractor who can perform an air test as part of the work.[47] If homeowners undertake the air sealing work, significant cost savings can be achieved, but the resulting energy savings would typically be reduced significantly as well. As noted in the table above, this cost is assumed to be slightly lower for attached homes.

Similar savings are assumed for this measure in new homes but lower incremental costs are used in the analysis, as noted above. The life of this measure is approximately 25 years. However, some elements of air leakage sealing, such as weather stripping and calking, require more frequent replacement; consequently, an annual equipment O&M cost of $20 has been added to account for this.[48]

[47] Based on personal communication with Tony Woods, CanAm Building Envelope Specialists.

[48] Energy impacts are from HOT2000 simulations; cost data are based on discussions with installation contractors. Similar estimates were used in recent studies for Enbridge and BC Hydro.

Attic Insulation

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing
Costs	$600 full cost in single detached $450 full cost in attached
Savings	5% of HVAC energy
Useful Life	30 years

Insulation levels can be increased in attics/ceilings by blowing insulation into the attic spaces to fill and cover the space within the roof frame. One technique is to make sure loose-fill or batt insulation fills the attic floor joists fully and then add an additional layer of unfaced fibreglass batt insulation across the joists. To reduce cost, it is also possible to blow in cellulose insulation (~$0.50/ft^2 for R-20) on top of the existing insulation.[49] This analysis assumes attic insulation is improved to RSI-7.0 (R-30).[50]

It is estimated that the incremental cost of this measure is about $600 in single detached homes and $450 in attached homes (due to their smaller size), with resulting savings of approximately 5% of the space heating costs. Energy savings from air conditioning and ventilation fans, if applicable, would be approximately the same percentage. The life of this measure is estimated at 30 years.[51]

Wall Insulation

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing
Costs	$1,600 incremental cost in single detached $1,200 incremental cost in attached
Savings	13% of space heating energy 5% of space cooling and ventilation energy
Useful Life	30 years

Wall insulation is usually challenging to retrofit in an existing home because the inside surfaces of the exterior walls are already finished. It is sometimes possible to add insulation to a wall by blowing insulating materials into the wall cavity, if sufficient space exists. Alternatively, if the siding is old and due for replacement, rigid foam insulation can be added before the new siding is installed. Since the cost of implementing this measure at full cost is very high, it is assumed that the homeowner is replacing the home's siding and improving the wall insulation on an incremental basis.

[49] Based on personal communication with Tony Woods, CanAm Building Envelope Specialists.

[50] Although the current standards for attic insulation are much higher (R-40 or R-50), HOT2000 modeling has shown that the additional energy savings resulting from these levels of insulation may not warrant the additional costs. Thus, a more conservative level of insulation is assumed here.

[51] Energy impacts are from HOT2000 simulations; cost data are based on discussions with retailers and installation contractors. Lifetime is based on Enbridge 2004 CPR.

Insulation levels are assumed to increase to RSI-3.5 (R-20).[52] In this situation, it would also be quite cost effective to install a more effective vapour and air barrier (e.g., Dupont™ Tyvek®) to reduce the amount of air leakage through the walls.

The incremental cost of adding the exterior insulation, as not all walls have sufficient space for blown-in insulation, is assumed to be about $1,600 for single detached homes and $1,200 for attached homes. Savings are estimated to be 13% of space heating energy. Energy savings from air conditioning and ventilation fans, if applicable, would be approximately 5%. The life of this measure is about 30 years.[53]

Foundation Insulation

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing and new
Costs	$40/m^2 incremental cost in existing • $2,500 incremental in existing detached • $2,000 incremental in existing attached
Savings	13% of space heating energy
Useful Life	30 years

In older homes the basement is often under-insulated or even left un-insulated. Increasing the insulation level in basements can be achieved in a number of ways, including: constructing a new insulated frame wall, moving the existing frame wall to increase the insulation level, adding extra insulation to the existing frame wall, adding rigid board insulation to the exterior of the foundation, or using a combination of interior and exterior rigid board insulation. As a lower cost alternative, it is also possible to use polyurethane foam (~$4/ft^2 for R-24, or 4 inches at R-6 per inch).[54]

For purposes of this report, increased basement insulation was assumed to be achieved by either moving an existing frame wall or constructing a new frame wall with an upgrade to RSI-4 (R-22.7) insulation. This measure is regarded as an incremental cost measure since it is most cost effective to implement when the basement is being finished or redone. Co-benefits of improved basement insulation include improved thermal comfort, fewer drafts, and more usable living space. If properly installed, improved basement insulation can also result in less condensation.

The incremental cost of adding insulation to the foundation is approximately $40/m^2 (~$4/ft^2) of basement wall area, or $2,500 for a typical single detached dwelling and $2,000 for a typical attached dwelling. Adding this insulation reduces space heating energy by about 13%. Energy savings from air conditioning and ventilation fans, if

[52] Unless the wall cavity is empty, the reliability of this upgrade measure cannot be certain. The cost of siding replacement is not included in the costs presented. If insulation is added under the siding, it is assumed to occur during a siding replacement project happening for other reasons.

[53] Lifetime is based on Enbridge 2004 CPR.

[54] Based on personal communication with Tony Woods, CanAm Building Envelope Specialists.

applicable, are not significant for this measure. This measure has a life of approximately 30 years.[55]

Crawlspace Insulation

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing
Costs	$600 full cost
Savings	5% of HVAC energy
Useful Life	30 years

Insulation levels remain below code in many homes that include crawlspaces as part of the basement design. If the floor is exposed, it would first be necessary to install a vapour barrier (e.g., 6 mil (600 gauge/0.15 mm) polyurethane barrier). Polyurethane foam could then be applied to the ceiling of the crawlspace. In addition to increasing the insulation of the crawlspace, this would help to eliminate any air leaks. Co-benefits include improved thermal comfort, fewer drafts and less condensation.

The addition of crawlspace insulation in existing houses to bring the thermal resistance values up to existing code levels of RSI-2.1(R-12) provides annual energy savings of approximately 5%. Energy savings from air conditioning and ventilation fans, if applicable, would be approximately the same percentage. This measure has a life of approximately 30 years. Typical installed costs depend on the size of the crawlspace but are about $600 on average.[56]

Vacuum Panel Insulation

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing and new
Costs	N/A
Savings	N/A
Useful Life	N/A

Vacuum panel insulation (VPI) can achieve thermal resistance levels that are three to seven times those provided by conventional insulation materials, such as rigid foam boards and fibreglass. The technology consists of a core panel enclosed in an airtight, vacuum-sealed envelope. Such panels can attain thermal resistances of approximately RSI-3.5/in. Although targeted primarily to refrigerators and specialized containers, VPI can be manufactured in any size and thus has potential for buildings.

Vacuum panel insulation for buildings is not currently commercially available.

[55] Energy impacts are from HOT2000 simulations; cost data are based on discussions with retailers and installation contractors. Lifetime is based on Enbridge 2004 CPR.

[56] Energy impacts are from HOT2000 simulations; cost data are based on discussions with retailers and installation contractors. Lifetime is based on Enbridge 2004 CPR.

Air Leakage Sealing and Insulation (Old Homes)

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing
Costs	$2,000 full cost in existing single detached $1,700 full cost in existing attached $10 annual equipment O&M cost in both
Savings	20% of HVAC energy
Useful Life	30 years

This measure is targeted at homes that are at least 30 years old, since many of these homes haven't had any work done in order to improve their insulation and air sealing deficiencies. If an upgrade is being considered for any portion of the building envelope of an older home, it is generally most effective to upgrade the insulation and the air sealing at the same time. This includes wall, attic, foundation, and crawlspace retrofits of older homes. For the purposes of this analysis, it is assumed that a retrofit is being conducted on the attic.

The air sealing portion of the work could be accomplished by segmenting the attic. In each segment, the existing insulation could be moved to one side and polyurethane foam sprayed in (serves as an air sealant in addition to its insulating properties). It may also be necessary to install or refurbish top plates to prevent airflow into the attic through exterior wall cavities. Other considerations that would increase the cost and may be present in some homes include sealing pot lights and kitchen or bathroom exhaust piping. When completed, these measures would dramatically improve the airtightness of an older home. The attic insulation could subsequently be cost-effectively improved by blowing in cellulose insulation (~$0.50/ft^2 for R-20) over the existing insulation.[57]

It is assumed that, on average, the air leakage rate is improved from 10 ACH @ 50Pa to 6 ACH and that the attic insulation is improved from RSI-1.76 (R-10) to RSI-5.29 (R-30).[58] Combined, these modifications represent energy savings of about 20% of HVAC energy.[59] Additional assumptions include a lifetime of 30 years and approximate costs of $2,000 and $1,700 for single detached and attached homes, respectively. In addition, an equipment O&M cost of $10 per year is added to reflect the cost of air sealing measures that can be completed and maintained by the homeowner, such as replacing weather stripping and caulking.

[57] Based on personal communication with Tony Woods, CanAm Building Envelope Specialists.

[58] Although the current standards for attic insulation are much higher (R-40 or R-50), HOT2000 modeling has shown that the additional energy savings resulting from these levels of insulation may not warrant the additional costs. Thus, a more conservative level of insulation is assumed here.

[59] Energy savings estimate based on HOT2000 models of old leaky homes with these energy-efficiency upgrades being implemented.

4.4.2 New Building Design

New building design integrates advances in both building envelope and space/water conditioning technologies. Two energy-efficiency upgrades that are applicable to new buildings were addressed:[60]

- High-performance Homes (EGH 80/R2000/ENERGY STAR®)
- Under-Slab Insulation.

High-Performance New Homes (EGH 80/R2000/ENERGY STAR®)[61]

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	New
Costs	$3,000 incremental cost
Savings	26% of all HVAC energy
Useful Life	30 years

There are several certification schemes for energy-efficient new homes that incorporate integrated design and multiple envelope measures. An EnerGuide for Houses rating is a standard measure of a home's energy performance, calculated by a professional EnerGuide for Houses advisor. The rating is based on information on the construction of the home and the results of a blower door test performed once the house has been built. A blower door test measures air leakage when the air pressure within the house is lowered a specified amount below the air pressure outside. EnerGuide ratings for new houses fall within the following ranges:

- Typical new houses: 70 to 74 (a house built to code would typically receive a rating of 72)
- Energy-efficient new houses: 77 to 82
- R2000 houses: 80 minimum
- Highly energy-efficient new houses: 80 to 90
- Advanced houses using little or no purchased energy: 91 to 100.

The R2000 standard is one method of achieving an EGH 80 rating. However, R2000 homes are required to achieve a stringent energy budget that is determined by a combination of factors related to heating fuel, house size and climatic data. In addition, R2000 homes are required to achieve an air tightness level of 1.5 ACH @ 50Pa. The key difference between the R2000 standard and the more flexible requirement to meet the EGH 80 rating is that builders do not need to install a heat recovery ventilator (HRV) or meet other environmental requirements of the R2000 program to achieve a rating of EGH 80. This substantially reduces the cost of the measure.[62] The ENERGY STAR® for New

[60] All input assumptions that are not otherwise referenced are from the Marbek internal database.

[61] Cost and savings values shown are based on best available data at the time of this study's assessment of this measure. Assumptions related to the cost and savings for this measure are currently under review and may result in improved economic attractiveness.

[62] The adequacy of ventilation levels in EGH 80 homes may be an issue in the absence of an HRV unit.

Homes program has requirements that are similar to the R2000 program and requires that homes be rated EGH 80.

This analysis estimates that annual space heating savings are 26% relative to standard, non-electrically heated new houses.[63] Electricity savings from air conditioning and ventilation fans, if applicable, would be approximately the same percentage. Typical incremental construction costs for an EGH 80 home are assumed to be $3,000.[64] In addition, a lifetime of 30 years is assumed.

Under-Slab Insulation

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	New
Costs	$4.85/m^2 or about $450 incremental cost
Savings	1.5% of space heating energy
Useful Life	New home lifetime

Several new basement slab insulation products have been developed in recent years. The most popular product for this application is 50mm extruded polystyrene panels. However, a recent CMHC study that compared different types of under-slab insulation concluded that the most cost-effective and best-performing product is composed of 44mm thick polyurethane with steel door skins on each side. This material was originally sourced from window cut-outs of steel-skin doors.[65]

The initial insulation value of the steel-skinned polyurethane was calculated to be RSI-2.56. However, the CMHC study noted that thermal performance of this product decreases moderately with age. Thus a lifetime average insulation value of RSI-2.0 is assumed for this analysis. Based on this assumption, this measure represents approximate space heating energy savings of 1.5%. The CMHC study estimates that the cost of the steel-skinned polyurethane material to be $4.85/m^2, or about $450 for a new home. Its lifetime is equivalent to that a new home.

4.4.3 Space Heating and Ventilation Equipment

Space heating refers to the equipment and controls used to heat residential dwellings. In addition, ventilation equipment circulates fresh air into the home. Nine energy-efficiency upgrade options were identified and assessed for this end use:[66]

- Condensing Furnaces

[63] Assuming a baseline EGH 73 home, which requires 35% more space heating energy than an EGH 80 home. Going from an EGH 73 home to an EGH 80 home represents savings of 35/135=26%. A footnote in Section 3.2 provides more detail on how energy consumption varies with EGH rating number.

[64] Energy impacts are from HOT2000 simulations; cost data are based on discussions with installation contractors (R2000 incremental cost, less the cost of installing an HRV).

[65] CMHC. Comparison of Under-Floor Insulation Systems, Oct. 2004.

[66] All input assumptions that are not otherwise referenced are from the Marbek internal database.

- Condensing Boilers
- High-Efficiency Heat Recovery Ventilators (HRV)
- Programmable Thermostats
- Integrated Mechanical Systems (Heating and DHW)
- Gas-Fired Heat Pumps
- Duct Sealing
- Furnace Tune-ups
- Solar Pre-Heated Make-Up Air.

Condensing Furnaces

Assumptions used for Analysis	
Target Segments	Single detached and attached
Vintage	Existing
Costs	$1,500 incremental cost
Savings	6% of space heating energy
Useful Life	18 years

High-efficiency condensing furnaces feature advanced heat exchanger designs that extract more heat from the flue gases before they are exhausted. So much heat is extracted that the flue gases condense and must be discharged as a condensate rather than a gas. As discussed in Section 3 (Reference Case), the federal government has proposed to increase the minimum performance standard of residential furnaces to 90% by the end of 2009. This means that mid-efficiency non-condensing furnaces (AFUE ~80%) will likely not be available before the first milestone of this study.

As a result, a condensing furnace with an efficiency of 90% is used as a base case and an upgrade to a furnace with an efficiency of 96% is assumed. This unit represents an incremental cost of roughly $1,500 over a 90% AFUE model and would provide about 6% savings in heating energy.[67] Some furnaces also feature variable speed fan motors that can save between 600 kWh/year to 700 kWh/year of the electrical energy use (at an additional incremental cost) but this feature is not assumed to be part of this measure. The typical life of a furnace is 18 years.[68]

Condensing Boilers

Assumptions used for Analysis	
Target Segments	Single detached and attached
Vintage	Existing and new
Costs	$3,200 incremental cost in new and existing
Savings	10% of space heating energy
Useful Life	25 years

[67] Cost information is based on a survey of six HVAC contractors in Southern Ontario.

[68] Efficiency ranges and costs are from manufacturer's estimates. Estimated life is from ASHRAE.

High-efficiency condensing boilers feature advanced heat exchanger designs that extract more heat from the flue gases before they are exhausted. So much heat is extracted that the flue gases condense and must be discharged as a condensate rather than a gas.

This analysis employs an incremental cost of $3,200 for a residential condensing boiler compared to the price of a mid-efficiency boiler. Non-condensing mid-efficiency boilers have AFUEs ranging from 80% to 87% while condensing high-efficiency units have AFUEs in the range of 88% to 97%. Thus, on average (comparing average efficiencies of 83.5% and 92.5%), an efficient condensing unit can reduce consumption by 10% compared to a non-condensing unit. A high-efficiency boiler also saves up to 50 kWh/year in electrical energy savings from the pump motor. The typical life of a boiler is 18 years.[69]

It should be noted that, in retrofit applications where condensing boilers are replacing non-condensing units, it may be necessary to modify the radiating system. Otherwise, the units may not actually condense the flue gas and realize their full efficiency potential. It is assumed that the cost of any necessary modifications is included in the incremental cost stated above.

High-Efficiency Heat Recovery Ventilators (HRVs)

Assumptions used for Analysis	
Target Segments	Single detached and attached
Vintage	New and existing
Costs	$650 incremental cost in new and existing
Savings	6.5% of space heating energy
Useful Life	15 years

Many new homes now have heat recovery ventilators installed to recover wasted heat energy from centralized exhausts. This analysis assumes that a standard heat recovery ventilator costs approximately $2,500 and results in a 13% reduction in space heating costs. It is further assumed that, in contrast to the standard HRV model, new, high-efficiency HRV units recover approximately 50% more of the energy escaping in ventilation air, which results in an additional 6.5% reduction in space heating costs.

It is also possible to install HRVs in existing homes, especially in cases where the occupants are concerned about air quality. In both new and existing homes, the incremental cost of installing more efficient HRVs rather than standard models is approximately $650. This technology has an estimated life of 15 years.[70]

[69] Efficiency ranges and costs are from manufacturer's estimates. Estimated life is from ACEEE (ASHRAE estimates life of a steel boiler at 25 years, and a cast iron boiler at 35 years).

[70] E-Source Heating Technology Atlas. Data used in 2007 BC Hydro Conservation Potential Review.

Programmable Thermostats

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached with central thermostat
Vintage	New and existing
Costs	$65 full cost in existing $65 incremental cost in new
Savings	12% of space heating 6% of space cooling and ventilation
Useful Life	18 years

Digital programmable thermostats provide improved temperature setting accuracy and are capable of multiple time settings. When combined with an assumed 4ºC temperature setback during night and unoccupied periods, typical space heat savings are in the range of 10% to 15% relative to the baseline, depending on the dwelling's vintage and type of detachment.[71] Other utility studies have indicated that a lower savings percentage should be used to reflect the fact that the thermostat's setback capabilities do not completely reflect how they are used.[72] For example, some home occupants reliably set back manual thermostats while others do not use the setback features on their electronic thermostats. For this study, it is assumed that programmable thermostats result in space heating savings of 12% and space cooling and ventilation savings of 6%.[73]

These thermostats can be installed in both new and existing dwellings. An incremental cost of $65 is assumed for new homes while a full cost of $65 is assumed for existing homes.[74] These units have an expected life of 18 years.[75]

Integrated Mechanical Systems (Heating and DHW)

Assumptions used for Analysis	
Target Segments	Single detached and attached
Vintage	Existing and new
Costs	$800 incremental cost in existing and new
Savings	33% of DHW energy
Useful Life	18 years

Integrated mechanical systems bring the most efficient technologies for residential space heating, water heating and ventilation into one package. For example, the Matrix system by NTI NY Thermal incorporate a condensing furnace, condensing boiler, condensing water heater and HRV all in one unit. Primary benefits of the integrated units include:

- Compact construction

[71] Canadian ENERGY STAR® Savings Calculator.

[72] Enbridge Gas Distribution, Inc., consumer awareness campaign literature, supported by unpublished internal studies.

[73] Savings based on Union DSM measure assumptions.

[74] Pricing based on Union DSM measure assumptions.

[75] Lifetime based on Union DSM measure assumptions.

- Lower cost of installation (only one set of gas, water and ventilation connections are required)
- The price for the integrated system is expected to be lower than the total price for comparable individual systems for heating air and water, once the technology is mature.
- Higher efficiency at lower installation and maintenance costs.

As discussed earlier, the minimum performance standards for furnaces are likely to be brought up to 90% efficiency by the end of 2009. Thus, condensing furnaces can be considered as the baseline and only the DHW savings of the integrated mechanical systems remain. Considering the efficiency improvements of condensing DHW units (see profile for condensing water heaters), reductions in gas use are approximately 33% for DHW energy. This conservative estimate doesn't take into account possible energy savings from the HRV system, which is sometimes integrated.

The estimated installed cost of integrated mechanical systems is approximately $800 more than for conventional furnace and DHW systems. The lifetime of integrated mechanical systems is about 18 years.[76, 77, 78]

Gas-Fired Heat Pumps

Assumptions used for Analysis	
Target Segments	Single detached and attached
Vintage	Existing and new
Costs	$4,000 incremental cost in existing and new
Savings	24% of space heating energy
Useful Life	25 years

Early gas-fired heat pumps, such as the York Triathlon, were unsuccessful due to their bulky size and poor quality design. A new generation of Gas Absorption Heat Pumps (GAHP) is currently available through Robur, an Italian manufacturer. These systems can either be ground-source or air-source (i.e., the heat sink may be either an underground fluid loop or an above ground heat exchanger coil). Air-source systems are substantially less expensive since they don't employ drilled underground fluid loops. However, they can also be much less efficient than ground-source versions since their efficiency is a function of outside air temperature.

Commercial-sized GAHP systems have been available in Canada since mid-2007 but residential-sized systems are not currently available outside of Europe.[79] However, it is anticipated that residential-sized units will become available in Canada within the study period. It is estimated that air-source systems can operate at temperatures as low as -

[76] Nichols, David. Emerging Technologies for a Second Generation of Gas Demand-Side Management, prepared for Enbridge Gas Distribution Inc. (EGDI), 2004.

[77] E Source Technology Profile on eKOCOMFORT.

[78] EKOCOMFORT.

[79] Personal communication with D-B Cooling Systems, Canadian distributor of Robur products.

29°C and have annual efficiencies of 105% in cold winter locations such as Montreal.[80] Compared to a mid-efficiency furnace with an efficiency of about 80%, this represents potential natural gas savings of about 24%. It is estimated that the incremental cost of air-source GAHP systems will be in the range of $4,000. The life of this measure is assumed to be 25 years.[81]

Unlike electric heat pump systems, GAHP do not require any auxiliary heating equipment. In addition, the lack of a mechanical compressor extends their lifetime and allows air-source systems to withstand more extreme temperatures.

Ground-source GAHP have efficiencies (COPs) ranging from 120% to 130% but are prohibitively expensive for most residential applications.

Duct Sealing

Assumptions used for Analysis	
Target Segments	Single detached and attached
Vintage	New and existing
Costs	$1,000 full cost
Savings	5% of HVAC energy
Useful Life	18 years

An estimated 15% to 30% of a home's heating and cooling energy leaks out of the ductwork. Air leaks in and out of ducts at all the connections within a system allow heated or cooled air to escape and, where the duct work is exposed to the outside, can also introduce additional outside air. Even with the heating and cooling system off, the leaks in the ducts increase the ventilation rate of the house, increasing the need for heating or cooling. The problem is particularly pronounced in homes where ductwork is external to the conditioned spaces (such as in the southern U.S., where it often runs through attics). In Canada, where most ducts run within the conditioned space, there is still savings potential. Reducing leakage into the basement will minimize overheating of little-used areas of the house. Reducing leakage can also eliminate the under-heating of rooms at the end of long duct runs, so the thermostat setting can be lowered.

Duct leakage is the result of improper installation and poor materials. Duct tape, which is commonly used, does not adequately seal joints between ducts and has a short life. More stable and permanent materials are needed such as foil tape, fiberglass tape and mastic, or new advanced duct tape. Lawrence Berkeley Laboratory has developed a method for internally sealing heating and cooling ducts using a pressurized aerosol sealant that can reduce duct leakage by up to 90%, reducing energy use by up to 25% in southern climates where ducts run through the attic. In Canada, the savings would be closer to 5%.[82]

[80] Gaz Métro. Unveiling the results of the geothermal natural gas demonstration project, June 2008.

[81] Personal communication with D-B Cooling Systems, Canadian distributor of Robur products.

[82] Marbek staff participated in studies of the LBL technology in Wisconsin in the mid-1990s to assess its potential in heating-dominated climates with interior ducts. The savings estimate of 5% comes from that first-hand experience.

The Aeroseal® method, marketed by Carrier, is based on this pressurized aerosol sealant. The sealing procedure involves quantifying the percentage of air leaking from the ductwork and identifying the sources of leaks. Next, all intake and exhaust ports are temporarily plugged and the adhesive particles are blown into the air duct system. These particles attach directly onto the edge of any hole or crack and accumulate there until these areas are sealed. This duct sealing process requires 4-8 hours.

A thorough sealing job performed by a knowledgeable contractor with good quality materials can typically reduce heating, cooling and ventilation energy costs by 10% to 20% in homes where the ducts mainly run outside the conditioned space, with costs ranging from $500 to $1,500.[83, 84] This analysis employs an estimate of 5% savings of HVAC energy, reflecting the construction standards more typical of the Ontario climate, where the ducts are within the conditioned space. A measure lifetime of 18 years is assumed.[85]

Furnace Tune-Ups

Assumptions used for Analysis	
Target Segments	Single detached and attached
Vintage	Existing
Costs	$100 full cost
Savings	2% of space heating and ventilation energy
Useful Life	3 years

In addition to improving the efficiency and extending the lifetime of natural gas furnaces, furnace tune-ups result in improved safety and comfort. A qualified professional will assess and adjust several things during a routine inspection/tune-up. For example, they will inspect the venting system, mechanical parts, furnace filter and interior of the combustion chamber. The burners are also generally removed and cleaned and the carbon monoxide level of the flue gas is assessed to ensure that the furnace is burning as cleanly as possible. Based on this assessment, it may be necessary to adjust the burners or air flow.

Other steps that are often carried out in a routine furnace tune-up include testing the heat exchanger for carbon monoxide leaks, checking and adjusting all controls, inspecting wiring and thermocouples and making recommendations on any repairs that are required to the furnace.

On average, it is estimated that furnace tune-ups result in a 2% reduction of space heating and ventilation energy. A low savings percentage is assumed since furnaces no longer incorporate primary air shutters. Thus, it is now more likely that the furnace is optimally burning its fuel. In addition, a cost of $100 and a lifetime of 3 years are assumed in this analysis.

[83] U.S. Department of Energy. ENERGY STAR®.

[84] From Toolbase Services: Technical Resource and discussions with contractors.

[85] BC Hydro, Power Smart. QA standard, Technology: Effective Measure Life, p. 10, Sept. 11, 2006.

Furnace Filter Alarms

Assumptions used for Analysis	
Target Segments	Single detached and attached
Vintage	Existing
Costs	$20 full cost
Savings	N/A
Useful Life	18 years

Furnace filter alarms, such as FilterTone™, are small (~3 inches in diameter) discs that attach to the blower side of furnace filters with push-on pins. As dirt builds up on the filter, the ventilation system must work harder to pull air through it. This increased pressure triggers the filter alarm, and it produces a continuous, pleasant tone to remind homeowners that it's time to clean or replace their filter. The filter alarm is easily removed and reinstalled. Furthermore, since the filter alarm operates much like a whistle, it doesn't require any batteries.

The cost of this product is about $20 and, due to its simple design, it is assumed that its lifetime is equal to that of a furnace, about 18 years.[86] Although filter alarms can extend the life of ventilation equipment and improve indoor air quality, research indicates that they do not result in space heating savings. In fact, filter alarms may cause furnaces to use more natural gas since ventilation fans motors don't need to work as hard. The motors would thus supply less heat to the system.

EnerGuide Natural Gas Fireplaces

Assumptions used for Analysis	
Target Segments	Single detached and attached
Vintage	Existing and new
Costs	$100 incremental cost in existing and new
Savings	20% of fireplace energy
Useful Life	15 years

All vented gas fireplaces sold in Canada must now be tested for their energy efficiency using the Canadian Standards Association CSA-P.4.1-02 standard, if they are shipped across provincial lines. The energy-efficiency rating of the fireplace is printed on the EnerGuide label. Fireplace efficiency ranges from about 20% to 80% but the average efficiency of natural gas fireplaces currently being sold is 60%.[87] EnerGuide recommends that direct vented fireplaces as the safest and most energy-efficient type of fireplace. EnerGuide does not set a minimum efficiency level, so savings are possible by using the EnerGuide label to choose the more efficient unit. The price of natural gas fireplaces has more to do with "add-ons" (e.g., mantles, etched glass, etc.) than with efficiency. As such, an incremental price of $100 is assumed for higher-efficiency models.

[86] Smarthome: Home Automatation Superstore. FilterTone Air System Filter Alarm.

[87] Based on NRCan presentation slide.

This analysis assumes fireplace energy savings of 20% (75% efficiency versus 60% efficiency). Installing a direct vented fireplace also reduces the heating load on the main heating appliance in the home (due to heat losses up the fireplace flue when not in operation). To be conservative, these additional savings have not been included in this analysis. The expected useful life is 15 years.

Solar Pre-Heated Make-Up Air

Assumptions used for Analysis	
Target Segments	Single detached and attached
Vintage	Existing and new
Costs	\$1,300 full cost in existing \$1,300 incremental cost in new
Savings	20% of space heating
Useful Life	20 years

Solar pre-heated ventilation systems consist of perforated steel or aluminum absorber sheets that are mounted vertically on a building's exterior surface. In order to collect the maximum amount of solar radiation, these systems are ideally mounted on southerly facing walls, plus or minus 20 degrees. The dark coloured metal sheets that make up the system are mounted 10 cm to 20 cm away from the building's surface, creating an air cavity between the building and the metal sheets. A negative pressure is created within the cavity by ventilation fans and air is drawn through holes that are typically 1/32" (0.08 mm) in diameter and spaced about 1 cm apart in the metal panels. Before being drawn into the building's ventilation system, the air in the cavity is heated by solar radiation that is absorbed by the dark metal sheets.

On a sunny day, these systems can raise incoming air temperatures by 25°C to 35°C.[88] The collector preheats incoming ventilation air and also reduces heat loss through the portion of the building shell covered by it. In summer months, ventilation air can be drawn directly from the outside through a bypass damper while heated air is rejected through vents at the top of the air cavity.

Several manufacturers produce these types of systems; the best known is the Solarwall® system, manufactured by Conserval Engineering. In addition, Matrix Energy manufactures the MatrixAir™ system while Enerconcept Technologies produces the Unitair™ system. These systems are generally used in commercial and industrial applications with buildings that have large areas of window-less walls. However, they have seen some limited residential use.

Conserval's Solarwall® panels cost about \$32/m^2 for steel and \$43/m^2 for aluminium. With fans, ducts, and controls, the installed cost is on the order of \$130/m^2 of Solarwall® system.[89] Required system size depends on several factors, including location, system orientation and size and required ventilation flow rate. However, a rough estimate based

88 SolSource Inc. Design Guide for the SolarWall™ Air Heating System.

89 Personal communication with Conserval Engineering.

on study results suggests that to achieve a 50% reduction in natural gas space heating use, one square meter of paneling should be used for every ten square meters of floor space.[90]

For this analysis, a 10 m^2 system is assumed due to limitations with residential window space and aesthetic issues. Based on the above analysis, this system is estimated to cost $1,300 and represent a 20% reduction in furnace space heating energy. The approximate lifetime of these systems is 20 years. New or existing homes with HRV systems are considered as the baseline for this measure.

As an added benefit, these systems supply homes with make-up air, a feature that is often not present in many homes. The collector surface can also protect aging building material such as brick or stucco in retrofit situations, further improving the financial payback period of these types of systems.

4.4.4 Domestic Hot Water (DHW)

Domestic hot water (DHW) refers to the heated water used for showers, baths, hand washing and clothes and dishwashing (DHW savings for clothes and dishwashers are treated separately in the Major Appliances end-use). Eleven energy-efficiency upgrade options were identified and assessed for this end-use:[91]

- Ultra Low-Flow Showerheads
- DHW Tank Insulating Blanket
- Hot Water Pipe Insulation
- DHW Heat Trap
- DHW Temperature Reduction
- Water Heater Timers
- Condensing Water Heaters
- Tankless Gas-fired DHW
- Wastewater Heat Recovery
- Solar Hot Water Systems (DHW)
- DHW Recirculation Systems (e.g., Metlund D'MAND®).

Ultra Low-Flow Showerheads

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing and new
Costs	$15 full cost
Savings	16% of DHW energy in existing 45% of personal use water
Useful Life	10 years

Ultra low-flow showerheads have aerators and flow restrictors to reduce water use. At 4.75 LPM (1.25 GPM), their flow rates are substantially lower than traditional low flow

[90] CANSIA. 50% Heat Savings with SolarWall, According to New Report.

[91] All input assumptions that are not otherwise referenced are from the Marbek internal database.

fixtures, whose flow rates range between 7.6 and 9.5 LPM (2.0-2.5 GPM). For this analysis, a baseline flow rate of 9.5 LPM (2.5 LPM) is assumed, partly due to the fact that low-flow fixtures have not completely penetrated the marketplace. Thus, some showerheads have flow rates above 10 LPM.

Based on this assumption, ultra low-flow showerheads result in a 50% reduction in hot water use for showers relative to traditional shower models. Since showers represent about 90% of personal use DHW (also includes faucets) and personal use is assumed to account for approximately 35% of total DHW energy, this represents a 16% reduction in DHW energy. Installed costs are approximately $15 for a single-family dwelling and this measure has an expected life of 10 years.[92]

Although ultra low-flow showerheads use substantially less water than even the low-flow fixtures, initial market studies have shown that customers are fairly accepting of the technology, with a low change-out rate of 5% to 6%.[93]

Hot Water Pipe Insulation

Measure Profile	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing
Costs	$1 full cost
Savings	3% of DHW energy
Useful Life	15 years

Hot water pipe insulation reduces the distribution losses for DHW, which account for approximately 5% to 10% of the total water heater energy consumption. In general, however, only the first one or two metres of pipe nearest the DHW tank are accessible enough to insulate. Insulating this section of piping affects both the delivery of hot water and the losses from the tank. Delivery temperature is slightly increased during a hot water draw and the water in the piping does not lose its stored heat as quickly between draws. In theory, the user may respond to the improved delivery temperature by using less hot water (mixing in a higher percentage of cold water, for example), and savings could be as much as 1% from these effects. In reality, users are unlikely to change their behaviour significantly, and the reduction in hot water consumption would be less than 1%. The reduction in losses from the tank is more significant, however. Approximately the first 60 cm of piping acts as a fin, dissipating heat from the tank 24 hours a day. 10 mm of insulation on the first metre or two of piping would reduce this loss by up to 80%, saving between 2% and 3% of DHW energy.

This analysis assumes that hot water pipe insulation reduces total DHW energy consumption by 3%.[94] The materials cost an average of $1 per house and are assumed to be installed by the homeowner. The measure has an expected life of 15 years.[95]

[92] Cost and lifetime assumptions are based on Union DSM measure assumptions. This cost reflects a program where these units are purchased in bulk.

[93] Based on market research performed by Union in 2008.

DHW Heat Trap

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing (pre-2004 water heaters)
Costs	$65 incremental cost
Savings	3% of DHW energy
Useful Life	9 years

Heat traps are installed on the exit side of the hot water tank to reduce thermal siphoning (i.e., prevent hot water from rising in the pipes when not in use) and related standby losses. A change in DHW tank performance standards in 2004 has meant that heat traps are now an integral component of new water heaters, so this measure only applies to tanks installed before this date. Furthermore, since heat traps are now included with new water heaters, this measure only applies to cases where the homeowner wishes to install this energy saving feature without replacing their water heater. The potential for this measure will diminish with time as older tanks are replaced.

This analysis estimates that in a typical application, total hot water consumption is reduced by about 3%.[96] Typical installed costs are assumed to be $65.[97] However, this installed cost represents the incremental cost of installing a heat trap if a plumber is already visiting the home for another reason. Having a plumber visit just to install a heat trap is deemed to be cost prohibitive. The lifetime of this measure is assumed to be about nine years, or equal to the expected lifetime of a new water heater minus the number of years that DHW heat traps have been mandatory. This accounts for the fact that water heaters must be at least four years old already in order for this measure to apply.

[94] The savings estimate is based on calculations that take into account heat loss from the piping due to both radial heat transfer (i.e., from the hot water in the piping) and axial heat transfer (i.e., from the pipe acting as a hot water tank fin).

[95] Cost and lifetime data based on Union DSM measure assumptions.

[96] Acker, L. Advanced Conservation Technology Inc. Improving the Efficiency of Hot Water Distribution Systems, ACEEE Forum, p. 12, 2008.

[97] Cost and savings data based on Enbridge 2004 CPR.

DHW Temperature Reduction

Measure Profile	
Applicable Dwelling Type(s)	Single detached and attached, where water heaters are set above 54°C
Vintage	Existing
Costs	No cost
Savings	2.5% of DHW
Useful Life	Remaining lifetime of water heater Existing: ~ 8 years

In some homes, residential hot water heaters are set at 60°C. This is becoming less common as most modern water heaters are delivered from the factory set to heat to approximately 54°C. For this reason, this measure is only considered for existing homes. In cases where this measure is applicable, reducing the temperature setting on a water heater doesn't typically result in a decrease in hot water consumption since users tend to adjust the amount of cold water to compensate for the reduced hot water temperature. Instead, it results in a reduction of the standby losses associated with hot water storage since it reduces the temperature difference between the heated water and the environment.

For each 1°C reduction in the water heater temperature set point, stand-by losses are reduced by about 2.5%.[98] To avoid an increased risk of bacterial growth in the tank, it is recommended that the hot water temperature not be lowered below 54°C.[99] Thus, a 6°C temperature reduction, which leads to a 15% reduction in stand-by losses, is assumed in this analysis. Since standby losses account for about 16% of DHW energy, this measure represents a potential 2.5% reduction in overall DHW energy. There is no cost associated with this measure since it can be performed by homeowners with minimal effort. In addition, its lifetime is equal to the remaining lifetime of the hot water heater.

Added benefits of this measure include a reduced risk of scalding and a reduction of mineral build-up and corrosion in both the hot water heater and pipes.[100] However, since dishwashers require water that is quite hot, this measure may increase the electricity consumption of many dishwashers by requiring them to use their booster heaters more extensively. This consideration is not addressed in this analysis.

As mentioned above, the potential savings for this measure are diminished, both in reality and in the model constructed for this study, by the fact that some water heaters are already set to 54°C by default. In addition, since most water heater controls are not marked for temperature, it can be difficult to accurately adjust temperature. To overcome this difficulty, hot water temperature can be measured at the tap.

[98] Assuming an ambient air temperature of about 20°C near the storage tank.

[99] Canadian Safety Council. Heated Debate about Hot Water, 2005.

[100] U.S. DOE. Energy Efficiency and Renewable Energy. Lower Water Heating Temperature for Energy Savings, 2007.

Water Heater Timers

Measure Profile	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing and new
Costs	N/A
Savings	N/A
Useful Life	N/A

Water heater timers can be used to shut off water heaters at times when they aren't being used (e.g., overnight, while at work). This concept is easily adapted to electric water heaters but is more difficult to implement in gas water heaters since many of them are not directly vented. However, this measure can be applied to power vented gas units.

Although this concept is reasonable in principal, water heater timers are redundant in practice. This is because water heater insulation and controls have improved to the point that water heaters can stay in standby mode for up to 15 hours if there is no hot water draw.[101] Therefore, this measure is not considered in the TRC analysis.

Condensing Water Heaters

Assumptions used for Analysis	
Target Segments	Single detached and attached
Vintage	Existing and new
Costs	$1,150 incremental cost in existing and new
Savings	32% of DHW energy
Useful Life	13 Years

Conventional storage water heaters have energy factors in the range of 0.58, meaning that they capture about 58% of the input energy. In contrast, condensing water heaters capture almost all of the heat value of the condensing flue gas water vapour to liquid (about 10% for natural gas), resulting in an overall efficiency of about 85%.[102] In addition, their forced draft burners eliminate off-cycle heat transfer to the flue.

The incremental cost of a condensing water heater relative to a conventional unit is estimated to be $1,150. Based on the efficiencies stated above, incremental DHW savings relative to a conventional water heater are assumed to be 32%. In addition, condensing water heaters are assumed to have a life of 13 years.[103, 104, 105]

[101] Personal communication with Union.

[102] Water heater efficiencies based on *Directory of Certified Product Performance*, Air Conditioning, Heating, and Refrigeration Institute (AHRI) in association with the Gas Appliance Manufacturers Association (GAMA), accessed Aug. 2008.

[103] Emerging Technologies for a Second Generation of Gas Demand-Side Management, 2004, submitted by David Nichols for Enbridge Gas.

[104] ACEEE. Emerging Energy-Saving Technologies and Practices for the Buildings Sector, 2004.

[105] ACEEE. Efficient Water Heating.

Tankless Gas-Fired DHW

Assumptions used for Analysis	
Target Segments	Single detached and attached
Vintage	Existing and new
Costs	$700 incremental cost in existing and new
Savings	33% of DHW energy
Useful Life	20 years

In-line tankless water heaters heat water on demand, eliminating hot water storage. The efficiency of tankless water heaters depends on the water heater's characteristics and on the temperature of the water being heated. Operating efficiencies can be as high as 90% but are more typically in the 75% to 80% range. The absence of hot water storage reduces standby heat losses. One concern with promoting the uptake of on-demand water heaters is that they have a very high energy demand, ranging from two to four times the maximum demand of a standard water heater. This is less of an issue with gas-fired units than it is for electric ones, which pose a significant demand problem for electric utilities. The savings may be somewhat overstated, because standby heat losses from a tank heater during the heating season contribute to meeting the space heating load. Eliminating these losses will tend to increase the gas consumption of the furnace. This effect has not been considered in the saving assumption.

Prices have dropped significantly in the recent past as the technology has matured; however, a significant price gap continues to exist between this technology and the standard tank system. The applicability of tankless gas-fired DHW systems is somewhat limited by venting constraints; the burner is significantly larger than for a standard water heater, so a larger vent is required. Some houses cannot accommodate the larger flue because of requirements for clearance from other structures, windows, etc.

A market-mature incremental cost of $700 is used in this analysis for a tankless water heater relative to a conventional water heater with a storage tank.[106] The seasonal efficiency of a tankless water heater is estimated to be 80%. In combination with reduced standby losses, this results in DHW energy savings of about 33% relative to a conventional tank system. Their useful life is assumed to be 20 years due to the high-quality materials used in tankless water heaters.[107, 108]

[106] This incremental cost is based on cost data from Enbridge Gas DSM measure assumptions. Based on numerous consultations with contractors, this source states that the average installed costs of conventional water heaters and tankless water heaters are $1,956 and $3,273, respectively. Accounting for the differing lifetimes of these water heaters (~12 years for conventional and ~20 years for tankless) and the discount rate employed in this study, the incremental cost of tankless water heaters was found to be about $830. Over the study period, the incremental cost between these technologies is likely to decrease due to maturing technology and increased sales volumes. Thus, a market mature incremental cost of $700 is assumed in this study.

[107] ACEEE. Emerging Energy-Saving Technologies and Practices for the Buildings Sector, 2004.

[108] ACEEE. A Comparative Study of High-Efficiency Residential Natural Gas Water Heating, 2002.

Drain Water Heat Recovery

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing and new
Costs	$900 full cost in existing $700 full cost in new
Savings	15% of DHW energy
Useful Life	20 years

Residential wastewater heat recovery systems transfer waste heat from drains to pre-heat make-up water. These systems work well only for DHW uses in which the hot water use and the draining of wastewater are simultaneous. Thus, in homes, application to anything other than showers is difficult. Examples of this technology include the GFX system, originally developed with a grant from the U.S. Department of Energy and currently manufactured by Doucette Industries, and the Powerpipe, designed and manufactured by RenewABILITY Energy Inc., a firm based in Waterloo, Ontario. These heat recovery systems incorporate shell-and-tube heat exchangers that typically have efficiencies in the range of 40% to 55%. The cost of these systems varies according to the application, the heat exchanger length and the installation difficulty.

This analysis estimates that, on average, the incremental costs are $900 in existing homes and $700 in new homes. The savings are assumed to be approximately 48% of DHW used for showers.[109, 110] Showers represent about 90% of the personal use of DHW, which in turn is approximately 35% of overall DHW energy use. Thus, the savings potential is approximately 15% of total DHW energy use. The life of this measure is assumed to be 20 years.

Solar Hot Water Systems (DHW)

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing and new
Costs	$7,000 full cost in existing $7,000 incremental cost in new $70 annual equipment O&M cost in new and existing
Savings	60% of DHW energy
Useful Life	25 years

Solar DHW systems use the energy of the sun to heat water. The primary components of a solar water heating system are a solar collector, a heat transfer fluid and a well-insulated storage tank. Due to Canada's colder climate and the higher likelihood of freezing, active closed-loop systems are generally used. These systems use a pump to

[109] RenewABILITY Energy Inc. Power-Pipe: Backgrounder for Homes.

[110] Natural Resources Canada. Sustainable Buildings and Communities. Drain Water Heat Recovery Characterization and Modeling, July 19, 2007.

circulate a non-freezing heat transfer fluid through the collectors and then through a heat exchanger so that the thermal energy can be transferred to the water.

Two different types of solar collectors are used in solar DHW systems. Glazed flat-plate collectors are insulated shallow rectangular boxes that consist of a tempered glass cover and a black backing to which dark tubing is affixed. The tubing runs back and forth along the dark backing in a serpentine fashion and the heat transfer fluid flows through it. Evacuated tube collectors are made up of rows of parallel transparent glass tubes. Each tube consists of an inner glass tube and an outer glass tube. The space between the tubes is evacuated to reduce heat loss and the inner tube is coated with a special dark coating that absorbs the maximum solar radiation possible. The heat transfer fluid flows within the inner, thermally isolated, tube. Dark fins are also sometimes attached to the inner tube to improve heat transfer. These types of systems work well when cold weather and/or high water temperature are involved.

Solar DHW systems only partially offset the energy requirements of DHW, thus a conventional water heating system is typically used in conjunction with the solar system. Based on a recent study that was completed for the Ontario Ministry of Energy, solar DHW systems can offset about 60% of a home's DHW energy in both service regions.[111,112] Based on this study, the cost of an average solar DHW system is $7,000 and its expected lifetime is 25 years. A 1% annual equipment O&M cost of $70 is assumed in this analysis.

DHW Recirculation Systems (e.g., Metlund D'MAND®)

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing and new
Costs	$500 full cost
Savings	16% of DHW energy 16% of water for personal use
Useful Life	18 years

When turning on the hot water tap, it is often necessary to wait for extended periods of time before hot water begins to flow from it. This effect is especially prevalent in older homes and is dependent on factors such as the distance between the point of use and the hot water tank and the location, type and diameter of piping being used. While waiting for hot water to flow from the tap, the lukewarm water exiting from it is usually flushed down the drain.

DHW recirculation systems can be used to pump hot water to a faucet at the demand of the user. Lukewarm water that is in the hot water lines is pumped back to the water heater either through the cold water lines or through a dedicated line. This pumping

111 Marbek Resource Consultants. Characterization of the Ontario Residential Solar Hot Water Industry: Draft Final Report, for the Ontario Ministry of Energy, July 15, 2008.

112 Calculations verified for both regions being considered using RETScreen. Solar fraction is largely dependent on the desired water heating temperature; 54°C is assumed in this analysis.

continues until the temperature of the hot water at the point of use reaches a specified value. In retrofit situations, this pumping system is generally installed at the faucet furthest away from the water heater and the system is enabled by remote activation from the other points of use.

On average, systems such as the Metlund Hot Water D'MAND® get hot water to the fixture four to five times quicker than traditional systems.[113] Along with improved convenience and water savings (since water isn't flushed down the drain), energy savings are achieved since the water that is pumped back to the water heater is generally warmer than city water. In addition, since the pump gets water to the fixture more quickly, there is an overall reduction of hot water use.

It is difficult to estimate savings from this measure since hot water use is difficult to predict and highly behaviour-dependent. However, based on a 2001 case study of five buildings, it was estimated that DHW recirculation systems could reduce water consumption by 30,000 L per year and DHW energy use by 16% to 32%.[114] Since the homes that were used in the study were all quite old (more than 50 years), the lower end of this scale, or 16% DHW savings, is assumed as an average for this analysis.

The material cost (not including installation) of Metlund D'MAND® systems was found to vary from $250 to $500, depending mostly on the pump size that is required for each application. An average installed cost of $500 and a lifetime of 18 years are assumed in this analysis.

4.4.5 Major Appliances

Major appliances include clothes washers, dishwashers, ranges and clothes dryers. Four energy-efficiency upgrade options were identified and assessed for this end use:[115]

- High-Efficiency Gas Ranges
- High-Efficiency Gas Dryers
- DHW Savings from Efficient Dishwashers
- DHW and Dryer Savings from Efficient Clothes Washers.

High-Efficiency Gas Ranges

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing and new
Costs	$650 incremental cost
Savings	20% of cooking energy
Useful Life	20 years

[113] Manufacturer's website, ACT Metlund D'MAND Systems.

[114] Oak Ridge National Laboratory. Water and Energy Savings using Demand Hot Water Recirculating Systems in Residential Homes: A Case Study of Five Homes in Palo Alto, California, Sept. 2002.

[115] All input assumptions that are not otherwise referenced are from the Marbek internal database.

Since gas stovetops involve cooking with an open flame, where combustion is difficult to control and thus inherently inefficient, there is potential for energy-efficiency improvements. Some recent innovations include improved gas valve rotation, meaning that flames exit the valve at a larger proportion of its diameter. This allows for more even heating and a broader range of control from high to low. In addition, some burners bring the flame closer to the surface, spread it over a larger area, and attempt to radiate any wasted heat upwards.

The efficiency of gas ovens can be improved if they include convection cooking features. Convection improves heat transfer to food and can lead to significant reductions in cooking time.

It is assumed that the incremental cost of energy-efficient gas ranges is $650.[116] These units result in a 20% approximate reduction in natural gas consumption for cooking. A lifetime of 20 years is used for this measure.[117]

High-Efficiency Gas Dryers

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing and new
Costs	$50 incremental cost
Savings	5% of dryer energy (natural gas)
Useful Life	13 years

Since fuel switching is beyond the scope of this study, this measure assesses the savings potential of high-efficiency gas dryers as compared to conventional gas dryers. The major distinction with energy-efficient models is that they incorporate termination controls to sense dryness and turn off automatically. The most efficient models have moisture sensors in the drum for sensing dryness, while other lower-cost and slightly less efficient models infer dryness by sensing the temperature of the exhaust air.

The majority of the retail models currently available employ some type of dryness sensing technology. An incremental cost of $50 is assumed for models with moisture sensors rather than temperature sensors.[118] Models with moisture sensors offer potential natural gas savings of 5% over those with temperature sensors.[119] The lifetime of natural gas dryers is about 13 years.[120]

[116] Based on a retail scan of ranges with and without convection.

[117] BC Hydro, Power Smart. QA standard, Technology: Effective Measure Life, p. 10, Sept. 11, 2006.

[118] Based on a retail scan of low-cost gas dryers with and without moisture sensors.

[119] Citizen Gas. Buyer's Guide: Natural Gas Clothes Dryers.

[120] Flex your Power: Residential Product Guides.

DHW Savings from Efficient Dishwashers

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing and new
Costs	$50 incremental cost
Savings	41% of DHW dishwasher energy 41% of dishwasher electrical energy 41% of dishwater water
Useful Life	13 years

ENERGY STAR® dishwashers save energy by using improved technology for the primary wash cycle and by using less hot water to clean. Construction includes more effective washing action, energy-efficient motors and other advanced technologies, such as sensors, that determine the length of the wash cycle and the temperature of the water necessary to clean the dishes. In addition, some advanced dishwashers can sense and adjust for the amount of soil on dishes, using only as much water as necessary.

As of January 1, 2007, the ENERGY STAR® level for dishwashers was changed with a corresponding increase in energy efficiency from 26% better than standard to 41% better. These savings affect both the energy used for heating the water and the mechanical energy of the dishwasher. The incremental cost of a unit meeting these new criteria is assumed to be $50.[121] The estimated life of a dishwasher is 13 years.[122]

DHW and Dryer Savings from Efficient Clothes Washers

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	Existing and new
Costs	$500 incremental cost
Savings	70% of DHW used for clothes washing 50% of clothes washer electricity 35% of dryer energy 70% of water for clothes washing
Useful Life	14 years

In January 2007, the ENERGY STAR® standard for clothes washers was increased. As a result, the large majority of clothes washers that currently meet ENERGY STAR® requirements are front-loading (horizontal axis) models. Compared to standard models, front-loading clothes washers use 60% to 80% less hot water. In addition, mechanical energy use is reduced by about 50% and dryer energy is reduced by approximately 35%, due to faster spin cycle speeds.[123]

[121] Based on discussions with retailers.

[122] Canadian ENERGY STAR® Calculator.

[123] Savings data based on earlier analysis conducted for Terasen Gas.

This analysis assumes the energy savings outlined above. Incremental costs are assumed to be about $500 more than conventional non-ENERGY STAR® machines, although some high-end models have incremental costs of about $1,000.[124] Horizontal axis clothes washer designs also result in less wear and tear on and fewer wrinkles in clothes. They are assumed to have a life of 14 years.[125]

4.4.6 Swimming Pool Heating

The pool heating end use refers to natural gas heaters for swimming pools that are usually outdoors. The saturation of heated pools in Ontario is relatively low but, where they are present, pool heaters often use as much natural gas as the home's primary space heating appliance. Three energy-efficiency upgrade options were identified and assessed:[126]

- Insulating Swimming Pool Covers
- High-Efficiency Pool Heaters
- Solar Pool Heaters.

Insulating Swimming Pool Covers

Assumptions Used for Analysis	
Applicable Dwelling Type(s)	Single detached and attached
Vintage	New and existing
Costs	$1,200 full cost
Savings	40% of pool heating energy
Useful Life	10 years

Between 30% and 50% of the heat loss from a swimming pool is due to evaporation and can equate to about 500 MJ of lost energy per week. In an outdoor pool, this heat loss either adds to the cost of heating the pool or shortens the swimming season. In an indoor pool, the evaporation not only adds to the cost of heating the pool itself but must also be removed from the pool room by a ventilation system, further increasing the cost. Evaporation also increases the quantity of chemicals that must be added to the pool. A pool cover can reduce evaporation and other heat losses but can also reduce heat gains depending on the design.

An insulating vinyl pool cover is assumed for this analysis. Although substantially more expensive than the bubble type covers, insulating vinyl pool covers are much more robust, and thus, have much longer lifetimes. They are also more effective at trapping heat. This analysis assumes that the installation and regular use of a swimming pool cover will save 40% of the energy used for heating the swimming pool.[127] The reduction in pool chemicals is an additional benefit that is not included in the cost savings. For a

[124] Cost data based on retailer scan.

[125] Canadian ENERGY STAR® Calculator.

[126] All input assumptions that are not otherwise referenced are from the Marbek internal database.

[127] CanREN. How Can I Best Manage My Pool's Energy Use? 2002.

50 m^2 pool, a cover with a manual reel is assumed to cost about $1,200.[128] It is assumed that a swimming pool cover has a life of approximately 10 years.

High-Efficiency Pool Heaters

Assumptions used for Analysis	
Target Segments	Single detached and attached
Vintage	Existing and new
Costs	$2,900 incremental cost
Savings	11% of pool heating energy
Useful Life	15 years

High-efficiency pool heaters incorporate advanced heat exchangers, forced draft combustion systems, pilot-less ignitions and innovations in hydraulics, which result in performance efficiencies between 90% and 95%, compared to efficiencies of 80% to 85% for standard models. If a pool heater is more than eight years old, it is likely only 65% to 75% efficient.

This analysis assumes that the incremental cost of a high-efficiency pool heater is $2,900 and energy savings are 11% relative to a standard efficiency model.[129]

Solar Pool Heaters

Assumptions used for Analysis	
Target Segments	Single detached and attached
Vintage	Existing and new
Costs	$1,850 full cost
Savings	100% of pool heating energy
Useful Life	20 years

Solar pool heaters are similar to solar DHW systems in some respects but do not include storage tanks, and, since they are only used in warmer weather, they generally employ unglazed solar collectors that are mounted of the roofs of houses. These types of collectors are designed for low-temperature applications and are made of some type of polymer. The heat transfer fluid flows within the polymer in a serpentine array. Although solar DHW systems do require a pump, its consumption is similar to that used in natural gas pool heaters.

Solar pool heaters can completely offset the natural gas consumption of conventional pool heaters. They are also much simpler than solar DHW systems and more affordable. Based on a recent study conducted for NRCan and assuming a 7.4 m^2 (80 ft^2) system, the approximate average cost of solar pool heaters is $1,850.[130] A lifetime of 20 years is assumed for this analysis.

[128] Cost data is based on supplier quotes.

[129] Personal communications with Jandy pool heater manufacturers.

[130] Marbek Resource Consultants. Basis of Payment and Level of Incentives for ecoENERGY For Renewable Heat Program, prepared for Natural Resources Canada, March 31, 2008.

5. ECONOMIC POTENTIAL FORECAST

5.1 INTRODUCTION

This section presents the Residential sector Economic Potential Forecast for the study period (2007 to 2017). The Economic Potential Forecast estimates the level of natural gas consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost effective. In this study, "cost effective" means that the technology upgrade passes the measure total resource cost (TRC) test, as discussed in Section 4.

The discussion in this section is organized into the following subsections:

- Major modelling tasks
- Technologies included in economic potential forecast
- Presentation of results
- Interpretation of results.

5.2 MAJOR MODELLING TASKS

By comparing the results of the Residential sector Economic Potential Forecast with the Reference Case, it is possible to determine the aggregate level of potential natural gas savings within the Residential sector, as well as identify which specific building segments, end uses and technologies can provide the most significant opportunities for savings.

To develop the Residential sector Economic Potential Forecast, the following tasks were completed:

- The measure TRC results for each of the energy-efficiency upgrades presented previously in Exhibits 4.4 and 4.5 were reviewed. The results of the economic analysis for each measure can be found in Appendix A.

- Technology upgrades that had positive measure TRC results were selected for inclusion either on a "full cost" or "incremental" basis. Technical upgrades passing the measure TRC test on a "full cost" basis were implemented in the first forecast year. Those upgrades that only passed the measure TRC test on an "incremental" basis were introduced as the existing stock reached the end of its useful life. If more than one cost-effective measure existed for the same end use application, the study selected the most energy-efficient one.

- Energy use within each of the dwelling types was modelled with the same energy models used to generate the Reference Case. However, for this forecast, the remaining standard efficiency technologies included in the Reference Case forecast were replaced with the most efficient "technology upgrade option" that passed the measure TRC test.

- When more than one upgrade option was applied to a given end use, the first measure selected was the one that reduced the energy load. For example, measures to reduce the overall DHW load (e.g., low-flow showerheads and more efficient dishwashers) would be applied before a high-efficiency water heater. Similarly, the cost effectiveness of the high-efficiency water heater was tested at the new, lower annual load and included only if it continued to pass the measure TRC test.

5.3 TECHNOLOGIES INCLUDED IN ECONOMIC POTENTIAL FORECAST

Exhibit 5.1 provides a listing of the technologies selected for inclusion in this forecast. In each case, the exhibit shows:

- End use affected
- Upgrade option(s) selected
- Dwelling types to which the upgrade options were applied
- Rate at which the upgrade options were introduced into the stock.

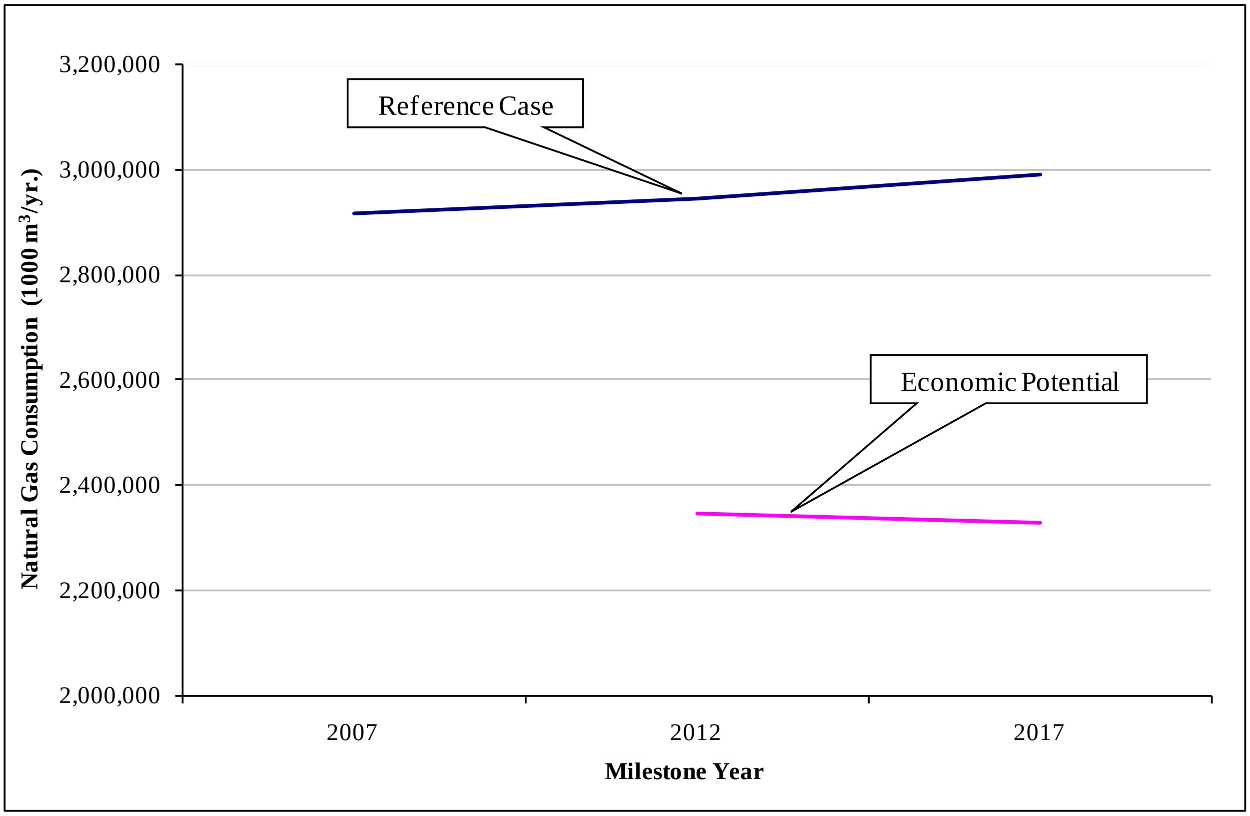
Exhibit 5.1: Technologies Included in Economic Potential

End Use	Upgrade Option	Applicability of Upgrade Options by Dwelling Type	Rate of Stock Introduction
Space Heating	Air sealing and insulation (old homes)	• All existing except Southern Attached	• Old existing homes, immediate
	High -and Super-high performance windows	• All	• New construction, immediate • Existing, at rate of window replacement
	Programmable thermostats	• All	• Immediate
	Solar pre-heated make-up air	• All SFD/Duplex with make-up air systems and/or HRVs	• At rate of renovation for other reasons
DHW	Savings from new washers and dishwashers	• All	• See below for appliances
	Ultra low-flow showerheads	• All Existing	• Immediate
	DHW pipe insulation	• All existing	• Immediate
	DHW temperature reduction	• All	• Immediate
	Instantaneous gas-fired DHW	• All existing or new SFD/Duplex	• New construction, immediate • At rate of heater replacement
	DHW recirculation systems (e.g., Metlund D'MAND®)	• SFD/Duplex, except for new Northern SFD/Duplex	• New construction, immediate • Existing construction, where feasible, immediate
Appliances	ENERGY STAR® dishwashers	• All	• Existing stock, at turnover • New stock, immediate
	ENERGY STAR® clothes washers	• All	• Existing stock, at turnover • New stock, immediate
Pools	Insulating pool cover	• All homes with existing gas heated pools	• Immediate
	Solar pool heater	• All homes with existing gas heated pools	• At rate of heater replacement • New stock, immediate
Fireplace	Efficient fireplaces	• All homes with fireplaces, except Attached new homes in Southern Region	• Existing stock, at turnover • New stock, immediate

5.4 PRESENTATION OF RESULTS

Exhibit 5.2 compares the Reference Case and Economic Potential Forecast levels of residential energy consumption. As illustrated, under the Reference Case residential natural gas consumption would grow from the Base Year level of approximately 2,925 million m^3/year to 2,999 million m^3/year by 2017. This contrasts with the Economic Potential Forecast, in which natural gas consumption would decrease to approximately 2,332 million m^3/year, a difference of approximately 666 million m^3/year or about 22%.

Exhibit 5.2: Reference Case versus Economic Potential - Natural Gas Consumption in Residential Sector, (1000 m^3/yr.)



5.4.1 Natural Gas Savings

Further detail on the total potential natural gas savings provided by the Economic Potential Forecast is provided in the following exhibits:

- Exhibit 5.3 presents the results by region and milestone year.
- Exhibit 5.4 presents the results by sub sector and milestone year.
- Exhibit 5.5 presents the results by end use and milestone year.
- Exhibit 5.6 presents the results end use, technology and milestone year.

Exhibit 5.3: Natural Gas Savings by Service Region and Milestone Year, (1000 m^3/yr.)

Milestone Year	Southern Region	Northern Region	Total	% Savings Relative to Ref Case
	1000 m^3/yr.			
2012	471,615	130,653	602,268	20%
2017	525,765	140,501	666,265	22%
% Savings 2017 Re: Reference Case	23%	21%	22%	
% Savings 2017 Re: Total	79%	21%	100%	

Exhibit 5.4: Natural Gas Savings by Dwelling Type and Milestone Year, (1000 m^3/yr.)

Dwelling Type	Milestone Year		% Savings 2017	
	2012	2017	Re: Ref Case	Re: Total
	1000 m^3/yr.			
Single-Family Detached/ Duplex	571,211	625,640	23%	94%
Attached/Row Housing/Tris & Quads	30,675	40,213	17%	6%
Other	382	412	20%	0%
Total	602,268	666,265	22%	100%

Exhibit 5.5: Natural Gas Savings by End Use and Milestone Year, (1000 m^3/yr.)

End Use	Milestone Year		% Savings 2017	
	2012	2017	Re: Ref Case	Re: Total
	1000 m^3/yr.			
Space Heating	275,993	273,060	15%	41%
DHW	243,312	301,322	43%	45%
Fireplaces	2,912	5,335	5%	1%
Dryers	6,942	13,811	22%	2%
Pool Heaters	73,108	72,738	72%	11%
Total	602,268	666,265	22%	100%

Note: DHW savings include savings from reduced DHW consumption by efficient clothes washers and dishwashers.

Exhibit 5.6: Natural Gas Savings and Benefit/Cost Ratios by End Use, Technology, and Milestone Year (1000 m^3/yr.)[131]

End Use	Technology	Economic Potential (1000 m^3/yr.)		Average B/C Ratio
		2012	2017	
DHW	Hot Water Pipe Insulation	12,045	8,925	64.84
DHW	Ultra Low-Flow Showerheads	110,360	109,616	17.93
Space Heating	Programmable Thermostats	80,568	82,446	11.86
Pools	Solar Pool Heaters	58,293	63,590	4.08
DHW	Efficient Dishwashers	21,603	41,051	3.73
Fireplaces	High-Efficiency Fireplaces	2,912	5,335	1.79
Pools	Swimming Pool Covers	14,815	9,148	1.74
Space Heating	High-Performance Windows	9,118	13,966	1.32
DHW	Tankless Gas-Fired DHW	17,803	31,063	1.15
Space Heating	Solar Pre-Heated Make-Up Air	25,528	25,037	1.09
Dryer	Efficient Clothes Washers	6,942	13,811	1.00
Space Heating	Air Sealing and Insulation (Old Homes)	150,937	132,646	1.00
Space Heating	Super High-Performance Windows	9,842	18,965	1.00
DHW	Efficient Clothes Washers	38,134	72,520	1.00
DHW	DHW Recirculation (Metland D'Mand)	36,971	32,747	0.77
DHW	DHW Temperature Reduction	6,396	5,400	N/A
TOTAL		602,268	666,265	

Note: Any difference in totals is due to rounding.

5.4.2 Electricity Savings

Implementation of the measures contained in the Economic Potential Forecast would also result in collateral electricity savings. For example, measures that improve the building envelope (such as efficient windows) also reduce furnace runtime, thereby saving ventilation fan energy. Similarly, ENERGY STAR® clothes washers and dishwashers use less electricity as well as less hot water.

Further detail on the total potential energy savings provided by the Economic Potential Forecast is provided in the following exhibits:

- Exhibit 5.7 presents the results by service region and milestone year
- Exhibit 5.8 presents the results by dwelling type and milestone year
- Exhibit 5.9 presents the results by end use and milestone year.

[131] DHW temperature reduction has no benefit/cost ratio, because it is essentially a no-cost measure.

Exhibit 5.7: Total Electricity Savings by Service Region and Milestone Year, (MWh/yr.)

Milestone Year	Southern Region	Northern Region	Total
	MWh/yr.		
2012	61,596	18,840	80,436
2017	93,423	28,690	122,112

Exhibit 5.8: Total Electricity Savings by Dwelling Type and Milestone Year, (MWh/yr.)

Dwelling Type	Milestone Year		Re: Total
	2012	2017	
	MWh/yr.		
Single-Family Detached/ Duplex	73,563	110,753	91%
Attached/Row Housing/Tris & Quads	6,802	11,251	9%
Other	71	109	0%
Total	80,436	122,112	100%

Exhibit 5.9: Total Potential Electricity Savings by End Use and Milestone Year, (MWh/yr.)

End Use	Milestone Year		Re: Total
	2012	2017	
	MWh/yr.		
Clothes Washers	11,399	24,292	20%
Dishwashers	8,462	18,985	16%
Space Cooling	28,587	37,273	31%
Ventilation	31,988	41,562	34%
Total	80,436	122,112	100%

5.5 INTERPRETATION OF RESULTS

Highlights of the results presented in the preceding exhibits are summarized below:

Savings by Service Region

The Southern region represents 79% of the identified savings. This is to be expected given the large number of customers in this service region.

Savings by Milestone Year

About 90% of the identified economic potential savings in 2017 were identified as economically feasible by 2012. This is because a large number of measures are cost effective at full cost (i.e., it is economically attractive to implement them before the equipment they affect or replace has reached the end of its useful life). Under the economic potential scenario, they would therefore be implemented right away. The other factor that causes 2012 savings to look relatively large as a proportion of 2017 is the natural conservation expected in the Residential sector over the course of the study. Savings are calculated based on the expected difference between the Reference Case forecast (which includes savings from natural conservation) and the Economic Potential Forecast. As naturally occurring savings gradually increase, they erode some of the economic potential.

Savings by Dwelling Type

Single-family dwellings and duplexes account for approximately 94% of the potential savings; this reflects their larger market share and their generally higher level of energy intensity per dwelling.

Savings by End Use

DHW accounts for approximately 45% of the total energy savings in the Economic Potential Forecast. There are several significant DHW energy-saving measures that are economically attractive, including ultra low-flow showerheads, efficient clothes washers and dishwashers, DHW recirculation systems and instantaneous gas-fired DHW systems.

Space heating accounts for approximately 41% of the total energy savings in the Economic Potential Forecast. The largest contributor to these savings is insulation and air sealing in older homes, followed by programmable thermostats, high- and super high-performance windows, and solar pre-heated air systems. While the building envelope measures offer substantial savings, their benefit/cost ratios are typically relatively low; i.e., it will be relatively expensive to achieve savings with programs targeting building envelope measures.

Swimming pool heaters account for approximately 11% of the total savings in the Economic Potential Forecast. Insulating pool covers account for about one sixth of the potential savings and solar pool heaters account for the remainder. Although only approximately 4% of residential gas customers have natural gas pool heaters, the large consumption per unit (on the same order of magnitude as a furnace) and the dramatic savings available (depending on usage patterns, a solar pool heater can reduce natural gas consumption to zero) mean that swimming pool measures offer substantial savings potential.

Clothes dryers account for approximately 2% of the total savings in the Economic Potential Forecast. These savings result from the faster spin cycles of efficient clothes washers.

Fireplaces account for approximately 1% of the savings in the Economic Potential Forecast. The savings measure is a fireplace (or insert) with an efficiency level of at least 75% as measured by EnerGuide. The potential for fireplace measures has been reduced in recent years because of the rise in average efficiency of units being sold.

Measure Summary

The most significant measures in terms of their overall economic saving potential are air sealing and insulation (old homes), ultra low-flow showerheads, programmable thermostats, efficient clothes washers, and solar pool heaters. Combined, these measures account for over 70% of the economic potential in 2017.

The most attractive measure in terms of its benefit/cost ratio is hot water pipe insulation. However, the potential savings for this measure represent only about 1% of the economic savings potential. The ultra low-flow showerheads, programmable thermostats, solar pool heaters, and efficient dishwashers measures all have very attractive benefit/cost ratios as well. However, the economic potential savings for each of these measures is also quite significant. Together, they represent nearly 45% of the economic potential in 2017.

5.5.1 Caveats on Interpretation of Results

A systems approach was used to model the energy impacts of the efficiency upgrades presented in the preceding section. In the absence of a systems approach, there would be double counting of savings and an accurate assessment of the total contribution of the energy-efficient upgrades would not be possible.

For example, a solar pre-heated make-up air system (e.g., SolarWall®) reduces space heating natural gas use, as does the installation of new energy-efficient windows. On its own, each measure will reduce overall space heating energy use. However, the two savings are not cumulative. The order in which some upgrades are introduced is also important. In this study, the approach has been to select and model the impact of measures that reduce the load for a given end use (e.g., wall insulation or window upgrades that reduce the space heating load) and then to introduce measures that meet the remaining load more efficiently (e.g., a high-efficiency space heating system).

The above approach means that where there is interaction between measures that affect the same end use, the savings for those individual measures shown in Exhibit 5.6 are reduced. For example, if the solar pre-heated make-up air system measure was implemented in the absence of any other space heating measures, its savings would be greater than those shown in Exhibit 5.6. As appropriate, this issue is addressed in the Achievable Potential section of this report.

6. ACHIEVABLE POTENTIAL FORECAST

6.1 INTRODUCTION

This section presents the Residential sector Achievable Potential natural gas savings for the study period (2007 to 2017). The Achievable Potential is defined as the proportion of the gross savings identified in the Economic Potential Forecast that could realistically be achieved within the study period.

The discussion is organized into the following sub sections:

- Description of Achievable Potential
- Approach to the Estimation of Achievable Potential
- Achievable Potential Workshop Organization
- Achievable Potential Workshop Results
- Achievable Potential Results
- Summary and Interpretation of Results

6.2 DESCRIPTION OF ACHIEVABLE POTENTIAL

Achievable Potential recognizes that it is difficult to induce all customers to purchase and install all of the energy-efficiency measures that meet the criteria defined by the Economic Potential Forecast presented in the preceding section.

Exhibit 6.1 presents an illustration of the level of natural gas consumption that is estimated in Achievable Potential scenarios. As illustrated in Exhibit 6.1, reductions in natural gas consumption under Achievable Potential are "banded" by the two forecasts presented in previous sections, namely the Reference Case and the Economic Potential Forecast.

Exhibit 6.1: Illustration of Achievable Potential Versus Reference Case and Economic Potential Forecasts

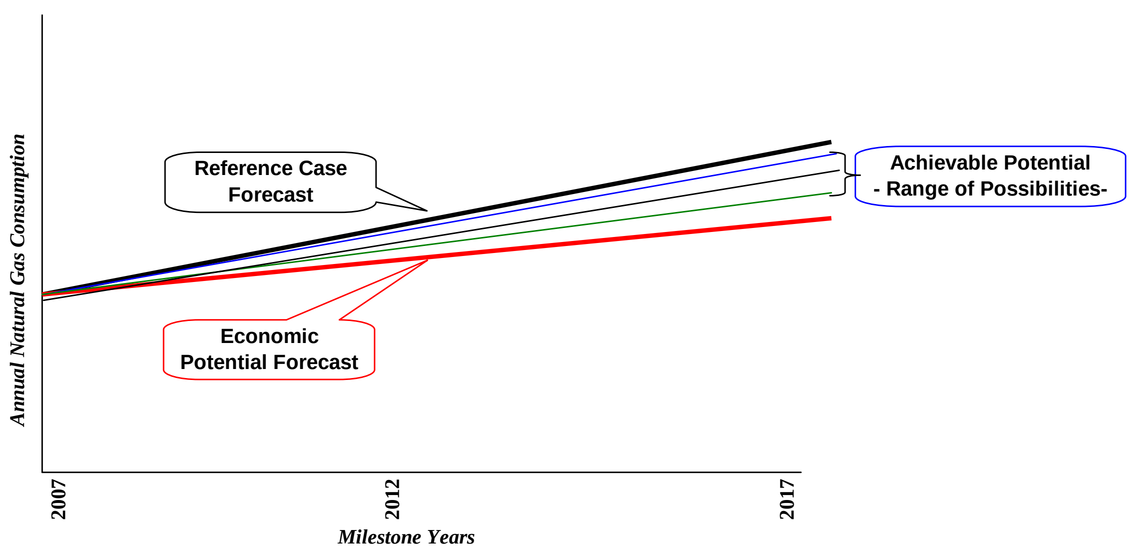


Exhibit 6.1 shows that future natural gas consumption under the Reference Case is greater than in any of the Achievable Potential forecasts. This is because the Reference Case represents a "worst case" situation in which there are no additional utility market interventions and hence no additional natural gas savings beyond those that occur "naturally."

Exhibit 6.1 also shows that future natural gas consumption under the Achievable Potential is greater than in the Economic Potential Forecast. This is because the Economic Potential Forecast assumes that efficient new technologies fully penetrate the market as soon as it is cost effective to do so. However, the Achievable Potential recognizes that under "real world" conditions, the rate at which customers are likely to implement energy-efficiency measures will be influenced by market constraints and, as a result, implementation will occur more slowly than under the assumptions employed in the Economic Potential Forecast. Exhibit 6.2 illustrates some of the types of market constraints that often affect customer implementation of energy-efficiency measures.

Exhibit 6.2 Illustration of "Typical" Market Constraints Affecting Energy-efficiency (EE) Implementation

Category	Barrier
Price Signals	• No monetization of externalities • Tax and subsidies that affect the playing field between EE and the fuels being displaced
Customer EE Awareness	• Awareness that EE opportunities and products exist • Awareness of benefits – cost and co-benefits • Customers' technical ability to assess the options.
Product and Service Availability	• Local or national product availability • Existence of a viable infrastructure of trade allies • Vendor or trade ally awareness of the efficiency options and their understanding of the technical issues
Financing of EE Measures	• Access to appropriate financing • Size of required EE investment vs. asset base • Payback Ratio – Actual vs. Required
Transaction Costs	• Level of effort/hassle required to become informed, select products, choose contractor(s) and install
Perceived Risk/Reward	• Level of perceived risk that the EE product may not perform as promised • Level of positive external/personal recognition for "doing the right thing" by installing the EE measure(s)
Split Incentive/Motivation	• Level to which the incentives of the agent charged with purchasing the EE are aligned with those of the person(s) that would benefit
Regulatory	• Codes or standards that prohibit implementation of innovative EE technologies • Level of EE performance that is required in codes or standards

The Achievable Potential scenarios shown in Exhibit 6.1 are presented as a range. This recognizes not only that any estimate of Achievable Potential over a 10-year period is necessarily subject to uncertainty but also that there are different types and levels of potential DSM program intervention. Government and utility DSM program experience throughout North America has shown that energy-efficiency market barriers can be addressed and customer willingness to accept and purchase energy-efficient products can be positively influenced by a variety of potential DSM market intervention strategies, such as those noted below in Exhibit 6.3.

The same body of DSM program experience also recognizes that there are limits to the scope of influence of any utility. It recognizes that some markets or sub markets may be so price sensitive or constrained by market barriers beyond the influence of utility DSM programs that they will only fully act if forced to by legal or other legislative means. It also recognizes that there are practical constraints related to the pace that existing inefficient equipment can be replaced by new, more efficient models or that existing building stock can be retrofitted to new energy performance levels. In addition, the design and implementation of DSM market interventions such as those noted in Exhibit 6.3 require staff and financial resources. In "real world" conditions these resources are also subject to constraints.

Exhibit 6.3 "Illustration" of Potential DSM Market Intervention Strategies[132]

Strategy Type	Description
Alliances	• Vertical integration of market between upstream and downstream market actors (i.e., forming a relationship between contractors and suppliers).
Audit	• An assessment of a building's energy efficiency made by a trained inspector.
Contractor Certification	• An assurance that a given contractor is knowledgeable about the product or service, verified through training and/or testing.
Demonstration	• Providing demonstration of the use/performance of energy-efficient technologies to market actors.
Design Assistance	• Providing recommendations on building or product design.
Financing	• Providing loans to finance the acquisition of a product or service.
Financial Incentives (and Rebates)	• Per measure dollars provided to market participants (generally either end users or distribution channel members) to encourage energy conservation measure installation.
Information	• Passive provision of information to market participants.
Linking Vendors & Customers	• Providing customer contacts to contractors, or contractor/vendor contacts to customers.
Non-Financial Incentives	• Products, changes in procedures, or administrative consolidation to encourage product or service provision.
Promotion	• Active advertising and information made available to the market.
Sales Training	• Providing sales, marketing and/or technical training about products or services to individuals responsible for selling it.
Standards, Labelling	• Setting specific standard levels for energy-efficient technologies. Labelling these technologies accurately for easy consumer/contractor recognition.
Technical Information	• Provision of technical information on energy-efficient products or services.
Technical Support	• Providing answer to technical questions from market actors about energy-efficient products/services after installation.
Technical Training	• Providing training to trade-allies so that they better understand new or existing practices or procedures.
Testing Protocols & Standards	• Standardization of testing protocols for installation and repair.
Third Party Verification	• Inspection and verification provided by an unbiased party on the results of an inspection to insure correct product or service performance.

Source: American Council for an Energy Efficient Economy (ACEEE) Proceedings: 2001.

[132] As in the preceding Exhibit, the strategies shown in Exhibit 6.3 are not necessarily exhaustive; rather, they illustrate the types of options that may be available to DSM program planners.

6.3 APPROACH TO THE ESTIMATION OF ACHIEVABLE POTENTIAL

Consistent with the description outlined above, this study approached the estimation of Achievable Potential by preparing a number of future scenarios, each representing differing assumptions related to the level of DSM program investment over the study period.

In consultation with Union personnel, the study identified two Achievable Potential scenarios to be assessed in this final stage of the study.[133] They are:

- A financially unconstrained DSM investment scenario
- A financially constrained DSM investment scenario, based on the maintenance of historic Union DSM program funding levels

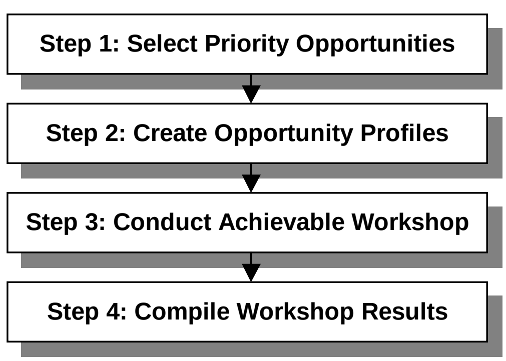
Development of the assumptions employed in each of the above scenarios was based on a combination of Union's own DSM program experience and the results of a one-day workshop involving Union DSM personnel, trade allies and consultant team members.

The workshop results were particularly valuable in generating the DSM investment scenarios; consequently, a brief description of the workshop organization and results is provided in the following sections.

6.4 ACHIEVABLE POTENTIAL WORKSHOP ORGANIZATION

The design and implementation of the Achievable Potential workshop was organized into four steps. The major steps are shown in Exhibit 6.4 and each step is briefly discussed below.

Exhibit 6.4: Approach to Achievable Potential Workshop



[133] It should be emphasized that the estimation of Achievable Potential scenarios is not synonymous with either the setting of specific program targets or with program design. While both are closely linked to the discussion of Achievable Potential, they involve more detailed analysis that is beyond the scope of this study.

Step 1: Select Priority Opportunities

The first step was to review the energy saving opportunities identified in the Economic Potential Forecast and to select a set of those opportunities for discussion in the Achievable Potential workshop. The amount of time available in the Achievable Potential workshop for the discussion of energy-efficiency opportunities was limited. Consequently, the number of opportunities selected for discussion in the workshop was limited to eight, which prior experience had shown to be about the maximum allowable within the available timeframe.

Exhibit 6.5 shows the eight energy-efficiency measures selected for inclusion in the workshop discussions. Selection of the opportunities was based on a qualitative application of criteria that were intended to ensure that the workshop discussions would include:

- Technologies and measures that represent a significant share of the potential energy savings identified in the Economic Potential Forecast
- Review of conditions in a variety of sub markets
- Consideration of new products or markets where little prior DSM experience existed.

Exhibit 6.5: Residential Sector Opportunity Areas

Opportunity Area	Title	Approximate % of Economic Savings Potential
R1a	ENERGY STAR® Windows	2%
R1b	Super-high Performance Windows	3%
R2	Air Sealing and Insulation for Old Homes	20%
R3	Efficient Dishwashers	6%
R4	DHW Recirculation Systems (e.g. Metlund D'MAND)	5%
R5	Instantaneous (Tankless) Water Heaters	5%
R6	Ultra Low-flow Showerheads	16%
R7	Solar Pool Heaters	10%
R8	Programmable Thermostats	12%
	Total	79%

Step 2: Create Opportunity Profiles

Brief profiles were prepared for each Opportunity selected in Step 1. The profiles, which were used to introduce the workshop discussion of each opportunity, provided the following information:

- **Technology description**, e.g., retrofit of existing windows to high-performance models

- **Sub sector and service region**, e.g. existing single-family detached home in Southern service region

- **Selection of a "Typical" application** for discussion purposes

- **Financial and economic indicators for the "Typical" application**, e.g., installed cost, useful life, annual energy savings simple payback, benefit/cost ratio, basis of assessment (incremental versus full cost)

- **Eligible participants** in each milestone period.[134]

Copies of the Opportunity Profile slides are provided in Appendix B.

Step 3: Conduct Achievable Potential Workshop

A one-day Residential sector Achievable Potential workshop was held on September 24, 2008. Workshop participants consisted of core members of the consultant team, DSM personnel from Union, and trade allies operating in the Union Gas franchise area. Together, the participants represented a wide range of expertise and experience related to both the DSM technologies and the markets that were discussed during the workshop.

Following a brief consultant presentation that summarized the study results to date, the workshop provided a structured assessment of each of the selected Opportunities. The assessment of each Opportunity began with a brief consultant presentation, as outlined in Step 2 above. The majority of each assessment consisted of a facilitated discussion of the key elements affecting successful promotion and implementation of the DSM Opportunity. More specifically:

- What are the major constraints/challenges constraining customer adoption of the identified energy-efficiency opportunities
  - How big is the "won't" portion of the market for this opportunity?

- Preferred strategies and potential partners for addressing the identified constraints (high level only)
  - Key criteria that determine customers' willingness to proceed
  - Key potential channel partners
  - Optimum intervention strategies e.g., push, pull, combo
  - How sensitive is this opportunity to incentive levels?

Following discussion of market constraints and potential intervention strategies, participants' views on potential participation rates were recorded. The achievable results were recorded as a band of possibilities. To facilitate workshop discussion, two "high-level" DSM program scenarios were defined:

- **The Aggressive Marketing scenario,** which assumes both an aggressive program approach and a very supportive context, e.g., healthy economy, very strong public commitment to climate change mitigation, etc. The results of this component of the

[134] For the purposes of the workshop, eligible participants were defined as: total population (e.g., existing single-family dwellings) minus those who have already installed the energy-efficiency measure (e.g., 10% of population) or, due to technical constraints, "can't" install the measure (e.g., 5% of population).

discussion provided valuable input into the estimation of the "Financially Unconstrained Scenario."

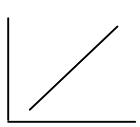
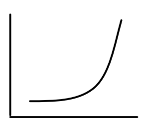
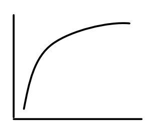
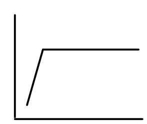
- **The Static Marketing scenario,** which assumes that market interest and customer commitment to energy efficiency and sustainable environmental practices remain approximately as current. Similarly, federal, provincial and municipal government energy-efficiency and GHG mitigation efforts remain similar to the present.

Exhibit 6.6 lists the steps employed in developing the estimated participation rates.

Exhibit 6.6: Workshop Process for Estimating Participation Rates

The steps involved were as follows:

- The participation rate for the Aggressive Marketing scenario in 2017 was estimated.
- The shape of the adoption curve was selected for the Aggressive Marketing scenario. Rather than seek consensus on the specific values to be employed in each of the intervening years, workshop participants selected one of four curve shapes that best matched their view of the appropriate "ramp-up" rate for each opportunity (see below).
- The process was then repeated for the Static scenario.
- Once participation rates had been established for the specific technology, sub sector and service region selected for the Opportunity discussion, workshop participants provided the consultants with guidelines for extrapolating the discussion results to the other sub sectors and service regions included in the Opportunity, but not discussed in detail during the workshop.

Curve A	Curve B	Curve C	Curve D
			

- **Curve A** represents a steady increase in the expected participation rate over the 10-year study period
- **Curve B** represents a relatively slow participation rate during the first half of the 10-year study period followed by a rapid growth in participation during the second half of the 10-year study period
- **Curve C** represents a rapid initial participation rate followed by a relatively slow growth in participation during the remainder of the 10-year study period
- **Curve D** represents a very rapid initial participation rate that results in virtual full saturation of the applicable market during the first milestone year of the 10-year study period.

Step 4: Compile Workshop Results

The results of the eight Opportunities discussed during the workshop were then aggregated and the results of the remaining Opportunities (identified in the Economic Potential Forecast but not discussed during the workshop) were extrapolated.

6.5 ACHIEVABLE POTENTIAL WORKSHOP RESULTS

A summary of the workshop results for each of the Residential sector Opportunities noted previously in Exhibit 6.5 is provided below. In each case, the following information is provided:

- Brief description of the Opportunity and the specific “typical” application selected for the workshop discussion

- Highlights from the workshop discussions related to:
  - Constraints and challenges
  - Potential strategies and partners
  - Incentive sensitivity

- Summary of the estimated participation rates under the Aggressive and Static Marketing scenarios for the selected sub sector
  - Shape of adoption curve selected by the workshop participants

- Summary of the major assumptions employed by the consultants for extrapolating the workshop results to other sub sectors.

6.5.1 R1a - ENERGY STAR® Windows

- **Description**

ENERGY STAR® windows incorporate features such as double glazing, low-e coatings, insulating spacers, argon fills and low conductivity frames to attain insulation values of at least RSI-0.5 (R-2.8). For discussion purposes, the workshop focused on new single detached homes in the Southern service region for this opportunity.

- **Discussion Highlights**

Constraints & Challenges

- The incremental cost of higher-efficiency windows is still significant
- Labelling is a major problem since consumers can’t tell the difference or the savings that each type of window represents
- The limited visual effect is also a major factor (i.e., homebuyers don’t recognize the benefits since they’re hidden. People are more likely to notice and value features such as granite countertops)
- Advances in the standard are possible over the study period but these windows will still represent the same percentage of savings over the baseline.

Potential Strategies and Partners

- ENERGY STAR® standards for windows vary significantly in different regions, based on typical local weather patterns
  - The large majority of Union customers are in Zone B and the incremental cost of these windows in this zone is quite low
- Other benefits of high-performance windows (e.g., improvements related to condensation) need to be “sold” in addition to energy benefits
- Education is vital; must educate both builders and buyers
- The current standard for ENERGY STAR® windows is likely to become the base case in the near future.

Incentive Sensitivity

- This measure is somewhat sensitive to incentive levels.

- **Participation Rates**

Workshop participants concluded that, under the conditions represented by the Aggressive Marketing scenario, a participation rate up to 100% could be achieved in new detached homes in the Southern service region by 2017. A gradually increasing adoption curve, Curve B, seemed the most likely to the workshop participants for the intervening years.

Under the more modest market conditions represented by the Static Marketing scenario, it was decided that the participation rate would only be slightly lower, perhaps 70%. A similar adoption curve would be followed in this case.

- **Participation Rates in Remaining Sub Sectors**

Based on the workshop discussions, it was decided that participation rates would be lower for attached homes and for homes in the Northern service region. The participation rates for existing homes were deemed to be about the same as those derived for new homes, although the measure would only be applied at the rate of natural stock turnover in these cases.

6.5.2 R1b - Super High-performance Windows

- **Description**

To attain insulation values of at least RSI-1.0 (R-5.7), super high-performance windows incorporate features such as triple glazing, transparent insulating films and fibreglass frames. These windows offer additional energy-efficiency gains when compared to ENERGY STAR® windows. For discussion purposes, the workshop focused on new single detached homes in the Southern service region for this opportunity.

❑ Discussion Highlights

Constraints & Challenges

- Cost is the major limiting factor
- Labelling is a major problem since consumers can't tell the difference or the savings that each type of window represents
- The limited visual effect is also a major factor (i.e., homebuyers don't recognize the benefits since they're hidden. People are more likely to notice and value features such as granite countertops)
- Penetration is extremely low right now (generally a luxury option)
- Not every company knows how to handle such windows due to their weight.

Potential Strategies and Partners

- May be beneficial to use a "push" strategy rather than a "pull" strategy (i.e., go up the chain and offer incentives/guaranteed pricing to builders)
- Other benefits of super high-performance windows (e.g., improvements related to condensation) need to be "sold" in addition to energy benefits
- Education is vital; must educate both builders and buyers.
- Retrofit market looks a lot like the custom new build market
- Homes that are oriented towards the south may represent an important sub market (i.e., greatest benefits could be realized here).

Incentive Sensitivity

- Measure is very incentive sensitive.

❑ Participation Rates

Under the conditions represented by the Aggressive Marketing scenario, workshop participants concluded that a participation rate of 30% could be achieved in new detached homes in the Southern service region by 2017. It was also decided that a gradually increasing adoption curve, Curve B, seemed the most likely for the intervening years.

Under the more modest market conditions represented by the Static Marketing scenario, it was decided that the participation rate would be about 3%. A similar adoption curve would be followed in this case.

❑ Participation Rates in Remaining Sub Sectors

Based on the workshop discussions, it was decided that participation rates would be lower for attached homes and for homes in the Northern service region. However, the participation rates for existing homes were deemed to be much higher than those derived for new homes. For existing homes, this measure would only be applied at the rate of natural stock turnover.

6.5.3 R2 - Air Sealing and Insulation for Old Homes

- **Description**

Weatherization measures are often not cost effective if assessed on an average home but they can have a much larger impact on older homes (considered to be at least 30 years old in this analysis). This measure sought to address the large potential presented by older homes by considering separate measures for air sealing and attic/ceiling insulation. For discussion purposes, the workshop focused on existing single detached homes in the Southern service region for this opportunity.

- **Discussion Highlights**

Constraints & Challenges

- Air sealing is usually incorporated with other measures (difficult to sell even though it's very effective in older homes)
- Important to properly seal and insulate the attic, otherwise the increased moisture and heat that is kept inside the home can have a significantly negative impact on roof lifetime
- There seems to be a shortage of air sealing contractors.

Potential Strategies and Partners

- Important to try to group these measures. Can dramatically improve savings for a small increase in cost
- Example niche market for wall insulation is for homes that are replacing the siding (i.e., can improve insulation and air sealing at the same time for a small incremental cost)
- Important to form a strategic alliance between all weatherization contractors, including air sealers, insulators and window installers.

Incentive Sensitivity

- This measure is somewhat sensitive to incentive levels.

- **Participation Rates**

This opportunity was presented at the workshop as two different measures: air sealing for old homes and attic insulation for old homes. From the workshop discussion, it became clear that it was more reasonable for air sealing and insulation to be regarded together as a bundled measure, especially since cost savings can be realized. Further discussion pointed to the fact that the cost assumptions being used were a little low. Since changes were required in framing this opportunity, workshop participants were not able to provide participation rates or adoption curves for either of the marketing scenarios. Participation rates for the resulting air sealing and insulation measure were developed through consultant experience and subsequent consultations with workshop participants.

6.5.4 R3 - Efficient Dishwashers

- **Description**

This measure discusses ENERGY STAR® dishwasher models, which are at least 41% more efficient than what is required by the minimum energy performance standards for dishwashers. Savings include DHW energy (natural gas), electricity (for motor and booster) and water. For discussion purposes, the workshop focused on existing single detached homes in the Southern service region for this opportunity.

- **Discussion Highlights**

Constraints & Challenges

- Free ridership for this measure will be very high, which is obviously negative from a program perspective.

Potential Strategies and Partners

- The retail industry is largely driven by "spiffs" (i.e., small bonuses which are offered to salespeople, either by manufacturers or employers, for the sale of a product)
- May need to train salespeople so that they are able to communicate the advantages of energy-efficient models to customers
- Other energy-efficiency features include timers and the ability to choose whether both levels or just top or bottom racks are to be cleaned.

Incentive Sensitivity

- This measure is thought to have a fairly low sensitivity to incentives.

- **Participation Rates**

Workshop participants concluded that, under the conditions represented by the Aggressive Marketing scenario, a participation rate up to 100% could be achieved in existing detached homes in the Southern service region by 2017. It was also decided that adoption Curve C best represents the fit with the pace of participation in the intervening years. Under the more modest market conditions represented by the Static Marketing scenario, it was decided that the participation rate would be the same and would follow a similar adoption curve in the intervening years.

- **Participation Rates in Remaining Sub Sectors**

Based on the workshop discussions, it was further decided that participation rates would be similar in the Northern service region but slightly lower for attached homes. The participation rates for new homes were deemed to be about the same as those derived for new homes.

6.5.5 R4 - DHW Recirculation Systems (e.g., Metlund D'MAND)

- **Description**

DHW recirculation systems, such as the Metlund D'MAND system, reduce wait times for hot water to reach the tap by a factor of four or five. These systems consist of a pump, valves and a temperature sensor/timer that are all installed at the point of use furthest from the water heater. Lukewarm water in the hot water lines is recirculated back to the inlet of the hot water tank. In addition to reducing the overall water consumption, this reduces DHW energy since the water returning to the tank is warmer than the municipal water supply. For discussion purposes, the workshop focused on existing single detached homes in the Southern service region for this opportunity.

- **Discussion Highlights**

Constraints & Challenges

- A very large detractor is that savings data for this product is very hard to substantiate
    - A limited number of studies have been done on these types of products
    - Needs more field validation, especially in Canada
    - Difficult to design effective testing for this type of technology
- Not well recognized and difficult even for professionals to identify source of savings
- Early stage of market entry, thus DHW recirculation systems are hard to find and installers may not be familiar with them
- Need both a plumber and an electrician in order to install
- Systems can be more effective if a dedicated line is used but cost is also much higher.

Potential Strategies and Partners

- Water savings go a long way in helping this measure pass the economic screen
    - In water-sensitive locations, this will be a much easier sell
- Important to sell co-benefits of technology
    - Can eliminate complaints for hot water wait times, especially effective in new homes and rental units
    - Potential for slight increase in water heater lifetime, due to reducing the shock of cold water (affects the enamel coating of water heaters)
- Important for this product to become recognized by ENERGY STAR® or LEED (especially important for penetration into new build market)
- Possibly an add-on to bathroom renovations but this could be a much slower channel.

Incentive Sensitivity

- Incentives are fairly important to this measure.

- **Participation Rates**

Workshop participants concluded that, under the conditions represented by the Aggressive Marketing scenario, a participation rate up to 10% could be achieved in existing detached homes in the Southern service region by 2017. A gradually increasing adoption curve, Curve B, seemed the most likely to the workshop participants for the intervening years.

Under the more modest market conditions represented by the Static Marketing scenario, it was decided that the participation rate would be quite low, perhaps 1%. A similar adoption curve would be followed in this case.

- **Participation Rates in Remaining Sub Sectors**

Based on the workshop discussions, it was decided that participation rates would be lower for attached homes (since many of these units are rented) and slightly lower in homes in the Northern service region. The potential participation rates for new homes were deemed to be about three times higher, in both the Aggressive and Static Marketing scenarios.

6.5.6 R5 - Tankless Gas-Fired Water Heaters

- **Description**

Tankless water heaters heat water on demand, eliminating stand-by losses associated with storage tanks. For discussion purposes, the workshop focused on new single detached homes in the Southern service region for this opportunity.

- **Discussion Highlights**

Constraints & Challenges

- Actual performance of tankless heaters may be much worse than advertised since efficiency testing is based on unrealistic operating conditions (i.e., testing based on fewer longer draws rather than many short draws)
- Lower cost units don't modulate (i.e., units can only be run at full power)
- In areas with hard water, lifetime could be even more limited
    - May have to install a water softener
- Often returned since they don't meet customer expectations, especially due to a weak support network and general unfamiliarity with these types of water heaters
- Difficult to overcome history of bad experiences.

Potential Strategies and Partners

- Passive systems are best since they can't malfunction nearly as easily.

Incentive Sensitivity

- This measure is somewhat sensitive to incentive levels.

- **Participation Rates**

Workshop participants concluded that, under the conditions represented by the Aggressive Marketing scenario, a participation rate up to 30% could be achieved in new detached homes in the Southern service region by 2017. A steady adoption curve, Curve A, was chosen as the best fit for participation rates in the intervening years. Under the more modest market conditions represented by the Static Marketing scenario, it was decided that the participation rate would be lower, perhaps up to 10%. A similar adoption curve would be followed in this case.

- **Participation Rates in Remaining Sub Sectors**

Based on the workshop discussions, it was decided that participation rates would be lower for attached homes and higher for homes in the Northern service region. The potential participation rates for existing homes were deemed to be about the same as those agreed upon for existing homes. For existing homes, this measure would only be applied at the rate of natural stock turnover.

6.5.7 R6 – Ultra Low-flow Showerheads

- **Description**

Ultra low-flow showerheads consume 4.75 LPM (1.25 GPM), while most traditional low flow models use 9.5 LPM (2.5 GPM). Thus, these showerheads can save about 50% of both the DHW energy and water associated with showers. For discussion purposes, the workshop focused on existing single detached homes in the Southern service region for this opportunity.

- **Discussion Highlights**

Constraints & Challenges

- 20% to 25% of customers will resist this product since they enjoy wand/Waterpik® showerheads
- Multiple setting models don't seem to be commercially available, but handheld version is currently available
- Potential problem may be a risk of shutdown with the plumbing systems in some homes if the flow rate is lower than 1.6 GPM.

Potential Strategies and Partners

- Has been found that performance issues are quite minimal
- Opportunity to educate homeowners since many don't realize how easy it is to replace their showerheads.

Incentive Sensitivity

- The very high benefit/cost ratio associated with this measure suggests that it is not sensitive to the incentive level.

- **Participation Rates**

Workshop participants concluded that, under the conditions represented by the Aggressive Marketing scenario, a participation rate up to 75% could be achieved in existing detached homes in the Southern service region by 2017. It was also decided that adoption Curve C best represents the fit with the pace of participation in the intervening years.

Under the more modest market conditions represented by the Static Marketing scenario, it was decided that the participation rate would also be 75%. However, a steady adoption curve would best represent the intervening years in this case.

- **Participation Rates in Remaining Sub Sectors**

Based on the workshop discussions, it was decided that participation rates would be similar for both attached homes and homes in the Northern service region. Participation rates for new homes would be slightly higher (80%) and would follow the same adoption curves in the intervening years.

6.5.8 R7 - Solar Pool Heaters

- **Description**

Solar pool heaters generally employ unglazed solar collectors that are mounted on the roofs of houses. These systems are much simpler than solar DHW systems and much more affordable. For discussion purposes, the workshop focused on existing single detached homes in the Southern service region for this opportunity.

- **Discussion Highlights**

Constraints & Challenges

- Not easy to install in every house (best to have south or southwest orientation; distance from pool is also a consideration)
- Pool distributors and installers may be a barrier since they want to guarantee that their customers can swim for a certain length of season (i.e., many may not be recommending solar heaters as an option for new pools)
- Other barriers include aesthetics, maintenance issues and some poor systems that were installed in the past (i.e., may have a stigma for some people).

Potential Strategies and Partners

- Since this is a full cost measure and doesn't necessarily need to replace natural gas heaters, it can be promoted to customers as an add-on as well as a replacement
- Technology and market are fairly mature
- The lifetimes of these products have greatly improved in the recent past
- Important to have a strong educational component for a program related to this measure
    - Many customers may not realize that solar heaters can be used in conjunction with their existing heaters
- With growing concerns about climate change, promotional efforts can capitalize on the fact that solar panels are visible and provide tangible evidence that the customer is acting in an environmentally appropriate manner.

Incentive Sensitivity

- Not very sensitive to incentives since the measure is financially very attractive. Free ridership will also probably be very low.

- **Participation Rates**

Workshop participants concluded that, under the conditions represented by the Aggressive Marketing scenario, a participation rate up to 20% could be achieved in existing detached homes in the Southern service region by 2017. It was also decided that a steep and gradually levelling off adoption curve, Curve C, best represents the fit with the pace of participation in the intervening years.

Under the more modest market conditions represented by the Static Marketing scenario, it was decided that the participation rate would be 10%. The same adoption curve would apply in for this scenario.

- **Participation Rates in Remaining Sub Sectors**

Based on the workshop discussions, it was decided that participation rates would be lower for attached homes but similar for homes in the Northern service region. Participation rates for new homes would also be similar.

6.5.9 R8 - Programmable Thermostats

- **Description**

Programmable thermostats allow for temperature setback during nights and unoccupied periods. They also provide improved temperature setting accuracy and more efficient control systems. However, there is an important behavioural aspect associated with the use of these types of thermostats. For discussion purposes, the workshop focused on existing single detached homes in the Southern service region for this opportunity.

- **Discussion Highlights**

Constraints & Challenges

- Very difficult for customers to program some of these on their own
- Some customers may find them difficult to use, especially those who are older. These customers will resist having them installed and may even change them out if they've already been installed
- Proportion of homes that don't have the Internet is about 20%. These people are likely to resist other technologies as well.

Potential Strategies and Partners

- An educational component is needed since many homeowners believe that thermostats act like gas pedals
- Some homeowners may have to have the thermostat installed for them (i.e., could be associated with a furnace replacement).

Incentive Sensitivity

- This measure is somewhat sensitive to incentive levels.

- **Participation Rates**

Workshop participants concluded that, under the conditions represented by the Aggressive Marketing scenario, a participation rate up to 90% could be achieved in existing detached homes in the Southern service region by 2017. It was also decided that a steady adoption curve, Curve A, best represents the fit with the pace of participation in the intervening years.

Under the more modest market conditions represented by the Static Marketing scenario, it was decided that the participation rate would be 70%. The same adoption curve would apply in for this scenario.

- **Participation Rates in Remaining Sub Sectors**

Based on the workshop discussions, it was decided that participation rates would be much lower for attached homes but similar for homes in the Northern service region. Participation rates for new homes would also be similar.

6.5.10 Extrapolated Participation Rates for Remaining Opportunities

As noted previously, the workshop results were used as a reference point. This knowledge was combined with follow-up discussions with some of the workshop participants and consultant experience to estimate participation rates for the remaining energy-efficiency opportunities contained in the Economic Potential Forecast. The extrapolated participation rates are summarized in Exhibits 6.7 and 6.13, presented in Section 6.6.

6.6 ACHIEVABLE POTENTIAL RESULTS

Consistent with the description presented earlier in this section, the Achievable Potential results are presented as a range, which is defined by the following two scenarios:

- A Financially Unconstrained scenario, in which potential is limited by market constraints but not by program budget
- A Static Marketing scenario, in which potential is limited by market constraints as well as DSM program budgets that are approximately similar to current Union levels (although the specific programs and technologies addressed would not necessarily be the same).

The results of each achievable scenario are presented below.

6.6.1 Financially Unconstrained DSM Investment Scenario

The Financially Unconstrained scenario provides an overview of the level of potential natural gas savings that could be achieved if a comprehensive portfolio of DSM programs was launched without any constraint on the availability of program funding. This scenario is based largely on the results of the Aggressive Marketing DSM scenario explored during the Achievable Potential workshop.

Although the results of this scenario are not constrained by program funding, the results do incorporate consideration of the market constraints identified during the Achievable Potential workshop (see Exhibit 6.2), such as product and service availability, customer transaction costs, etc.

This scenario, therefore, provides a high level estimate of the upper level of natural gas savings that could be achieved by Union's residential customers over the nine-year period beginning in 2009 and ending in 2017. It also provides Union's residential DSM program personnel with a view of the relative potential contribution of individual sub sectors, end uses, technologies and service regions.

Major Assumptions: Financially Unconstrained Scenario

- All measures that pass the measure TRC screen are included
- No program financial limit is set, except that all measures must continue to pass the measure TRC screen
- Participation rates are constrained by the market barriers noted in the workshop
- Participation rates for measures discussed in the workshop are employed directly and are shown in Exhibit 6.7. These measures are identified in the exhibit with a Workshop Reference #, and in the notes column. The 2017 participation rate and the adoption curve shape (from those shown in Exhibit 6.6) are those chosen by the workshop participants.
- Participation rates for the remaining measures are extrapolated from the workshop results and/or consultant experience and are shown in Exhibit 6.7. These measures in the exhibit have no Workshop Reference #. The extrapolation method is noted.
- Fixed program costs (e.g., advertising, training workshops, contractor certification etc.,) and incentive costs are included for each measure. The levels selected for the scenario are summarized in Exhibit 6.8. In each case the values shown draw on the workshop results and recent Union DSM program experience.

Exhibit 6.7: Participation Rates for Financially Unconstrained Scenario

Workshop Reference #	Upgrade Technology/Measures	Participation Rate 2017	Adoption Curve Shape	Notes
R1a	High-Performance Windows	100%	B	Workshop measure R1a
R1b	Super High-Performance Windows	30%	B	Workshop measure R1b
	Air Sealing and Insulation (Old Homes)	30%	B	Based on consultant experience
R8	Programmable Thermostats	90%	A	Workshop measure R8
	Solar Pre-Heated Make-Up Air	20%	B	Based on workshop measure R7
R6	Ultra Low-Flow Showerheads	75%	C	Workshop measure R6
R3	Efficient Dishwashers	100%	C	Workshop measure R3
	Efficient Clothes Washers	100%	C	Based on workshop measure R3
	DHW Temperature Reduction	50%	C	Based on consultant experience
	Hot Water Pipe Insulation	90%	A	Based on workshop measure R8
R4	DHW Recirculation (Metland D'Mand)	10%	B	Workshop measure R4
R5	Tankless Gas-Fired DHW	30%	C	Workshop measure R5
	High-Efficiency Fireplaces	50%	A	Based on consultant experience
	Swimming Pool Covers	50%	C	Based on consultant experience
R7	Solar Pool Heaters	20%	B	Workshop measure R7

Exhibit 6.8: Summary of Program Cost Assumptions – Financially Unconstrained Scenario[135]

Upgrade Technology/Measures	Fixed Program Costs ($/yr.)	Measure Basis	Measure Cost ($)[A]	Incentive Level (% of cost)[B]	Payback After Incentive (yrs.)
High-Performance Windows	50,000	Incr.	500	100%	0.0
Super High-Performance Windows		Incr.	950	100%	0.0
Air Sealing and Insulation (Old Homes)		Full	2,000	30%	5.0
Programmable Thermostats	50,000	Full	65	75%	0.1
Solar Pre-Heated Make-Up Air	50,000	Full	1,300	30%	4.7
Ultra Low-Flow Showerheads	440,000	Full	15	100%	0.0
Hot Water Pipe Insulation		Full	1	100%	0.0
Efficient Dishwashers	50,000	Incr.	50	100%	0.0
Efficient Clothes Washers		Incr.	500	20%	2.8
DHW Temperature Reduction	50,000	Full	N/A	0%	0.0
DHW Recirculation (Metland D'Mand)	50,000	Full	500	30%	4.9
Tankless Gas-Fired DHW	50,000	Incr.	700	100%	0.0
High-Efficiency Fireplaces	50,000	Incr.	100	50%	1.7
Swimming Pool Covers	50,000	Full	1,200	13%	2.4
Solar Pool Heaters		Full	1,850	11%	1.5

[A] Where measure cost varies by region and/or housing type, the cost for existing single detached homes in the Southern service region is shown

[B] The percentage of the cost reflects whether a full or incremental cost measure is being considered

Results: Financially Unconstrained Scenario

Under the conditions defined by the Financially Unconstrained scenario, total Residential sector natural gas savings in 2017 are estimated to be approximately 357 million m^3/yr. This represents a saving of approximately 12%, relative to the Reference Case and is equal to approximately 54% of the savings identified in the Economic Potential Forecast. Further detail is provided in the following exhibits:

- Exhibit 6.9 shows total natural gas savings by service region and milestone year.
- Exhibit 6.10 shows total natural gas savings by dwelling type and milestone year for the total Union Service Area.
- Exhibit 6.11 shows total natural gas savings by end use and milestone year for the total Union Service Area.

[135] Fixed program costs and incentive levels were provided by Union based on workshop results and current experience. Where fixed program costs apply to a bundle of measures, costs are distributed among the measures weighted by total savings potential. Salary and related overhead costs are not included in program cost estimates. Also, the incentive levels are capped at 100% of the indicated measure cost.

- Exhibit 6.12 shows annual natural gas savings for the year 2017, by technology, together with the estimated program costs and TRC benefits for the total Union Service Area. (Note: the values shown in Exhibit 6.11 are for the single year 2017 only; consequently, they do not add to the same values shown in the preceding exhibits.)

Exhibit 6.9: Natural Gas Savings by Service Region and Milestone Year, Financially Unconstrained Scenario (1000 m^3/yr.)

Milestone Year	Southern Region	Northern Region	Total	% Savings Relative to Ref Case
	1000 m^3/yr.			
2012	148,130	40,105	188,235	6%
2017	281,305	75,276	356,581	12%
% Savings 2017 Re: Reference Case	12%	11%	12%	
% Savings 2017 Re: Total	79%	21%	100%	

Exhibit 6.10: Natural Gas Savings by Dwelling Type and Milestone Year for the Total Union Service Area, Financially Unconstrained Scenario (1000 m^3/yr.)

Dwelling Type	Milestone Year		% Savings 2017	
	2012	2017	Re: Ref Case	Re: Total
	1000 m^3/yr.			
Single-Family Detached/ Duplex	175,460	332,182	12%	93%
Attached/Row Housing/Tris & Quads	12,657	24,176	10%	7%
Other	117	223	11%	0%
Total	188,235	356,581	12%	100%

Exhibit 6.11: Natural Gas Savings by End Use and Milestone Year for the Total Union Service Area, Financially Unconstrained Scenario (1000 m^3/yr.)

End Use	Milestone Year		% Savings 2017	
	2012	2017	Re: Ref Case	Re: Total
	1000 m^3/yr.			
Space Heating	55,827	133,973	7%	38%
DHW	117,635	190,789	27%	54%
Fireplaces	728	1,940	2%	1%
Dryers	5,207	12,075	19%	3%
Pool Heaters	8,838	17,804	18%	5%
Total	188,235	356,581	12%	100%

Note: DHW savings include savings from reduced DHW consumption by efficient clothes washers and dishwashers.

Exhibit 6.12: Annual Natural Gas Savings by Technology for One Year of Program Activity (2017) for the Total Union Service Area, Financially Unconstrained Scenario

End Use	Technology	Financially Unconstrained Potential 2017		Program Costs, 2017 (thousands $)	Program Costs per Unit	
		Gas Savings (1000 m^3/yr.)	TRC Benefits (thousands $)		per Natural Gas Savings ($/$m^3$)	per TRC Benefits ($/$)
Space Heating	High-Performance Windows	1,687	3,267	5,777	$3.42	$1.77
Space Heating	Super High-Performance Windows	712	0	3,147	$4.42	*
Space Heating	Programmable Thermostats	7,616	28,818	1,782	$0.23	$0.06
Space Heating	Solar Pre-Heated Make-Up Air	1,026	301	1,131	$1.10	$3.75
Space Heating	Air Sealing and Insulation (Old Homes)	7,561	6,081	9,908	$1.31	$1.63
DHW	Ultra Low-Flow Showerheads	828	4,503	332	$0.40	$0.07
DHW	Efficient Dishwashers	302	936	268	$0.89	$0.29
DHW & Appliances	Efficient Clothes Washers	623	2,000	438	$0.70	$0.22
DHW	DHW Temperature Reduction	30	69	50	$1.65	$0.73
DHW	Hot Water Pipe Insulation	908	2,993	277	$0.31	$0.09
DHW	DHW Recirculation (Metland D'Mand)	798	249	1,202	$1.51	$4.82
DHW	Tankless Gas-Fired DHW	112	62	418	$3.72	$6.78
Fireplaces	High-Efficiency Fireplaces	194	278	231	$1.19	$0.83
Pools	Swimming Pool Covers	46	50	10	$0.21	$0.19
Pools	Solar Pool Heaters	2,514	7,217	302	$0.12	$0.04
	Weighted Average				$1.01	$0.44

* Super high-performance windows have a positive TRC with respect to the base case, but not when compared to the high-performance windows. Therefore, the TRC benefits of the super windows are actually included in the line above.
Note: Program costs = fixed program costs plus incentives.

6.6.2 Static Marketing Scenario

The Static Marketing scenario is based largely on the results of the Static Marketing scenario explored during the Achievable Potential workshop. Consequently, it incorporates consideration of both market constraints and DSM program budget limitations, which are roughly consistent with current Union levels.

This scenario, therefore, provides a high level estimate of the level of natural gas savings that could be achieved by Union's residential customers over the nine-year period beginning in 2009 and ending in 2017, assuming present levels of program activity and a somewhat different mix of programs. It also provides Union's residential DSM program personnel with a view of the relative potential contribution of individual sub sectors, end uses, technologies and service regions.

Major Assumptions: Static Marketing Scenario

- All measures that pass the measure TRC screen are included
- Program spending levels are similar to current Union DSM activity, with a different mix of programs
- Participation rates are constrained by the market barriers noted in the workshop
- Participation rates for measures discussed in the workshop are employed directly and are shown in Exhibit 6.13. These measures are identified in the exhibit with a Workshop Reference #, and in the notes column. The 2017 participation rate and the

adoption curve shape (from those shown in Exhibit 6.6) are those chosen by the workshop participants.

- Participation rates for the remaining measures are extrapolated from the workshop results and/or consultant experience and are shown in Exhibit 6.13. These measures in the exhibit have no Workshop Reference #. The extrapolation method is noted.
- Fixed program costs (e.g., advertising, training workshops, contractor certification etc.,) and incentive costs are included for each measure. The levels selected for the scenario are summarized in Exhibit 6.14. In each case the values shown draw on the workshop results and recent Union DSM program experience.

Exhibit 6.13: Participation Rates for Static Marketing Scenario

Workshop Reference #	Upgrade Technology/Measures	Participation Rate 2017	Adoption Curve Shape	Notes
R1a	High-Performance Windows	70%	B	Workshop measure R1a, consultant experience
R1b	Super High-Performance Windows	3%	B	Workshop measure R1b
	Air Sealing and Insulation (Old Homes)	3%	B	Based on consultant experience
R8	Programmable Thermostats	70%	A	Workshop measure R8
	Solar Pre-Heated Make-Up Air	10%	B	Based on workshop measure R7
R6	Ultra Low-Flow Showerheads	75%	A	Workshop measure R6
R3	Efficient Dishwashers	100%	C	Workshop measure R3
	Efficient Clothes Washers	80%	C	Workshop measure R3, consultant experience
	DHW Temperature Reduction	40%	C	Based on consultant experience
	Hot Water Pipe Insulation	70%	A	Based on workshop measure R8
R4	DHW Recirculation (Metland D'Mand)	1%	B	Workshop measure R4
R5	Instantaneous Gas-Fired DHW	10%	C	Workshop measure R5
	High-Efficiency Fireplaces	20%	A	Based on consultant experience
	Swimming Pool Covers	20%	C	Based on consultant experience
R7	Solar Pool Heaters	10%	B	Workshop measure R7

Exhibit 6.14: Summary of Program Cost Assumptions – Static Marketing Scenario[136]

Upgrade Technology/Measures	Fixed Program Costs ($/yr.)	Measure Basis	Measure Cost ($)[A]	Incentive Level (% of cost)[B]	Payback After Incentive (yrs.)
High-Performance Windows	20,000	Incr.	500	50%	2.9
Super High-Performance Windows		Incr.	950	25%	6.1
Air Sealing and Insulation (Old Homes)		Full	2,000	10%	6.4
Programmable Thermostats	10,000	Full	65	30%	0.4
Solar Pre-Heated Make-Up Air	20,000	Full	1,300	10%	6.0
Ultra Low-Flow Showerheads	440,000	Full	15	100%	0.0
Hot Water Pipe Insulation		Full	1	100%	0.0
Efficient Dishwashers	20,000	Incr.	50	30%	0.9
Efficient Clothes Washers		Incr.	500	10%	3.1
DHW Temperature Reduction	20,000	Full	N/A	0%	0.0
DHW Recirculation (Metland D'Mand)	20,000	Full	500	10%	6.3
Tankless Gas-Fired DHW	20,000	Incr.	700	50%	3.0
High-Efficiency Fireplaces	20,000	Incr.	100	15%	2.8
Swimming Pool Covers	20,000	Full	1,200	8%	2.5
Solar Pool Heaters		Full	1,850	5%	1.6

[A] Where measure cost varies by region and/or housing type, the cost for existing single detached homes in the Southern service region is shown

[B] The percentage of the cost reflects whether a full or incremental cost measure is being considered

Results: Static Marketing Scenario

Under the conditions defined by the Static Marketing scenario, total Residential sector natural gas savings in 2017 are estimated to be approximately 261 million m^3/yr. This represents a saving of approximately 9%, relative to the Reference Case and is equal to approximately 39% of the savings identified in the Economic Potential Forecast. Further detail is provided in the following exhibits:

- Exhibit 6.15 shows total natural gas savings by service region and milestone year
- Exhibit 6.16 shows total natural gas savings by dwelling type and milestone year for the total Union Service Area
- Exhibit 6.17 shows total natural gas savings by end use and milestone year for the total Union Service Area
- Exhibit 6.18 shows annual natural gas savings for the year 2017 by technology, together with the estimated program costs and TRC benefits for the total Union Service Area. (Note: the values shown in Exhibit 6.11 are for the single year 2017 only; consequently, they do not add to the same values shown in the preceding exhibits.)

[136] Fixed program costs and incentive levels were provided by Union, based on workshop results and current experience. Where fixed program costs apply to a bundle of measures, costs are distributed among the measures weighted by total savings potential. Salary and related overhead costs are not included in program cost estimates. Also, the incentive levels are capped at 100% of the indicated measure cost.

Exhibit 6.15: Natural Gas Savings by Service Region and Milestone Year, Static Marketing Scenario (1000 m^3/yr.)

Milestone Year	Southern Region	Northern Region	Total	% Savings Relative to Ref Case
	1000 m^3/yr.			
2012	103,267	27,745	131,012	4%
2017	207,545	53,856	261,401	9%
% Savings 2017 Re: Reference Case	9%	8%	9%	
% Savings 2017 Re: Total	79%	21%	100%	

Exhibit 6.16: Natural Gas Savings by Dwelling Type and Milestone Year for the Total Union Service Area, Static Marketing Scenario (1000 m^3/yr.)

Dwelling Type	Milestone Year		% Savings 2017	
	2012	2017	Re: Ref Case	Re: Total
	1000 m^3/yr.			
Single-Family Detached/ Duplex	121,436	240,922	9%	92%
Attached/Row Housing/Tris & Quads	9,496	20,321	9%	8%
Other	80	158	8%	0%
Total	131,012	261,401	9%	100%

Exhibit 6.17: Natural Gas Savings by End Use and Milestone Year for the Total Union Service Area, Static Marketing Scenario (1000 m^3/yr.)

End Use	Milestone Year		% Savings 2017	
	2012	2017	Re: Ref Case	Re: Total
	1000 m^3/yr.			
Space Heating	34,812	74,198	4%	28%
DHW	87,527	168,134	24%	64%
Fireplaces	291	776	1%	0%
Dryers	4,165	9,660	15%	4%
Pool Heaters	4,217	8,634	9%	3%
Total	131,012	261,401	9%	100%

Note: DHW savings include savings from reduced DHW consumption by efficient clothes washers and dishwashers.

Exhibit 6.18: Annual Natural Gas Savings by Technology for One Year of Program Activity (2017) for the Total Union Service Area, Static Marketing Scenario

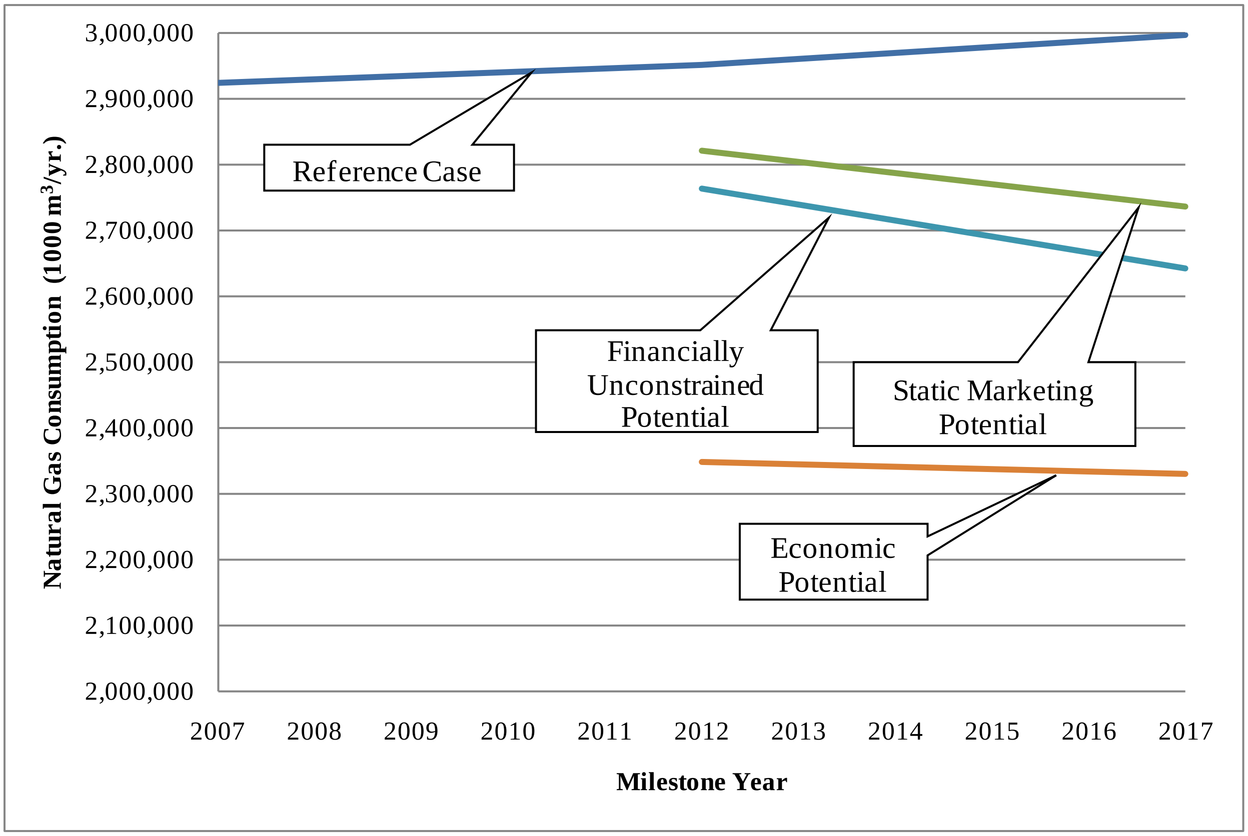
End Use	Technology	Static Marketing Potential, 2017		Program Costs, 2017 (thousands $)	Program Costs per Unit	
		Gas Savings (1000 m^3/yr.)	TRC Benefits (thousands $)		per Natural Gas Savings ($/$m^3$)	per TRC Benefits ($/$)
Space Heating	High-Performance Windows	1,215	2,351	2,081	$1.71	$0.88
Space Heating	Super High-Performance Windows	77	0	86	$1.12	*
Space Heating	Programmable Thermostats	6,062	22,942	561	$0.09	$0.02
Space Heating	Solar Pre-Heated Make-Up Air	531	156	207	$0.39	$1.32
Space Heating	Air Sealing and Insulation (Old Homes)	756	608	344	$0.46	$0.57
DHW	Ultra Low-Flow Showerheads	828	4,503	332	$0.40	$0.07
DHW	Efficient Dishwashers	306	949	83	$0.27	$0.09
DHW & Appliances	Efficient Clothes Washers	503	1,616	177	$0.35	$0.11
DHW	DHW Temperature Reduction	25	56	20	$0.81	$0.36
DHW	Hot Water Pipe Insulation	719	2,368	267	$0.37	$0.11
DHW	DHW Recirculation (Metland D'Mand)	83	26	60	$0.72	$2.34
DHW	Tankless Gas-Fired DHW	40	22	85	$2.14	$3.91
Fireplaces	High-Efficiency Fireplaces	78	111	42	$0.54	$0.37
Pools	Swimming Pool Covers	18	20	3	$0.15	$0.13
Pools	Solar Pool Heaters	1,293	3,712	85	$0.07	$0.02
	Weighted Average				$0.35	$0.11

* Super high-performance windows have a positive TRC with respect to the Reference Case, but not when compared to the high-performance windows. Therefore, the TRC benefits of the super windows are already included in the line above.
Note: Program costs = fixed program costs plus incentives.

6.7 SUMMARY AND INTERPRETATION OF RESULTS

Exhibit 6.19 provides a summary of the achievable natural gas savings under the Static Marketing and Financially Unconstrained scenarios presented in the preceding section. Results are shown relative to the Reference Case and Economic Potential Forecasts.

Exhibit 6.19: Achievable Potential versus Reference Case and Economic Potential Forecasts, for the Total Union Service Area



Further highlights are provided below.

The Financially Unconstrained Scenario

- Under the conditions defined by the Financially Unconstrained scenario, total Residential sector natural gas savings in 2017 are estimated to be approximately 357 million m^3/yr. This represents a saving of approximately 12% relative to the Reference Case and is equal to approximately 54% of the savings identified in the Economic Potential Forecast.

- The most significant opportunities for natural gas savings in this scenario are technologies that reduce space heating requirements. Air sealing in older homes is a particularly large opportunity in this scenario together with high-performance windows and programmable thermostats. Solar pool heaters are also a relatively large opportunity.

- Program costs per m^3 of natural gas savings in this scenario range widely by measure, from approximately \$0.12 for solar pool heaters to almost \$4.00 for tankless water heaters.

- Program costs per dollar of TRC benefit also show a wide range, from approximately \$0.04 for solar pool heaters to almost \$7.00 for tankless water heaters.

- Weighted averages for the whole group of measures show 2017 program costs of approximately $1.01/m^3 of natural gas savings and approximately $0.44/TRC dollar. These values are nearly five times higher than Union's current program results.[137]

The Static Marketing Scenario

- Under the conditions defined by the Static Marketing scenario, total Residential sector natural gas savings in 2017 are estimated to be approximately 261 million m^3/yr. This represents a saving of approximately 9%, relative to the Reference Case and is equal to approximately 39% of the savings identified in the Economic Potential Forecast.

- The most significant opportunities for natural gas savings are technologies that reduce space heating requirements, such as high-performance windows, programmable thermostats and air sealing in older homes. Solar pool heaters are also a relatively large opportunity.

- Program costs per m^3 of natural gas savings also range widely by measure in the Static Marketing scenario, from approximately $0.07 for solar pool heaters to over $2.00 for tankless water heaters.

- Program costs per dollar of TRC benefit show a similar wide range, from approximately $0.02 for solar pool heaters to almost $4.00 for tankless water heaters.

- Weighted averages for the whole group of measures included in the Static Marketing scenario show 2017 program costs of approximately $0.35/m^3 of natural gas savings and approximately $0.11/TRC dollar. These values are about 25% and 10% higher than Union's current program results, respectively.

Comparison of Scenarios

The distribution of savings potential changes significantly as the analysis moves from Economic Potential Scenario to the two achievable potential scenarios. The following observations may be made:

- Implementation of measures is spread out more evenly in the achievable scenarios. The "front loading" of savings in the Economic Potential scenario, because measures that pass at full cost are assumed to be implemented immediately, does not occur in the achievable scenarios, because market constraints are taken into account.

- There is no dramatic shift in the proportion of savings by region or by dwelling type when moving from one scenario to another.

- The savings by end use shifts substantially when moving from one scenario to another. In particular, space heating potential and pool heater potential account for a shrinking proportion of the overall savings as the analysis moves from Economic Potential to

[137] Union's audited results for its 2006 residential DSM programs show that program spending of $3,163,000 achieved natural gas savings of 11,375,000 m^3 and TRC net benefits of $31,614,000. Expressed as a ratio, one dollar of program spending generated approximately 3.6 m^3 (approximately $0.28/M^3) of annual natural gas savings and nearly $10 of TRC net benefits (approximately $0.10/TRC $).

Financially Unconstrained Potential and then to Static Marketing Scenario. In contrast, DHW measures assume an increasing relative importance. This is largely due to the assumptions about participation rates for the individual measures, arrived at during the achievable potential workshops.

- The relative importance of the different measures changes significantly from one scenario to another. Within the Economic Potential Scenario, the largest potential for natural gas savings in 2017 is contributed by Air Sealing & Insulation (Old Homes), Ultra Low-Flow Showerheads, Efficient Clothes Washers, and Programmable Thermostats.

    - Under the both of the achievable scenarios, the showerhead measure's contribution is reduced by two key factors: some consumers will be reluctant to install the new showerheads because of desired features only offered in higher flow fixtures; and, existing Union DSM programs have been aggressively promoting these showerheads, so the potential diminishes towards the end of the study period.

    - Under the two achievable scenarios, the clothes washer measure's contribution is reduced by two key factors: free ridership rates for these appliances are very high, as consumers adopt them for reasons other than the energy savings; and existing programs such as Energy Star are aggressively promoting the new clothes washers, so potential diminishes towards the end of the study period.

    - The air sealing and insulation measure in older homes is a relatively expensive measure and was judged to be very dependent on incentives and program activity; accordingly, it retains much of its relative importance under the Financially Unconstrained Achievable Potential, but its potential shrinks under the Static Marketing Scenario.

    - As some of the other significant measures shrink in importance from one scenario to the next, the programmable thermostats measure increases in importance.

7. CONCLUSIONS

This study has confirmed the existence of significant cost-effective DSM potential within Union's Residential sector customers.

Although the weighted average program cost values presented for both the Financially Unconstrained and the Static Marketing scenarios will vary depending on the specific composition of the future program portfolio, both scenarios show an evident trend towards higher future costs to achieve natural gas savings and TRC benefits.[138] This trend recognizes that savings from DSM programs tend to become more expensive with time as the most attractive measures gain greater market penetration and only the more challenging measures remain.[139]

In this specific case, one measure with which the Ontario gas utilities have had great success is the condensing residential furnace. Over half of the gas customers in Ontario now have high-efficiency condensing furnaces. Furthermore, the planned changes to the efficiency standards for gas furnaces will eliminate mid-efficiency furnaces from the marketplace after 2010. This change alone dramatically changes the economics of residential DSM programs in Union's Service Area.

7.1 ADDITIONAL OBSERVATIONS

In addition to the preceding conclusions, two additional observations warrant note as they may affect future program strategies. They include:

- ***Niche Markets Warrant Greater Program Focus:*** As the DSM market matures within Union's service area, niche or target markets are becoming increasingly important. For example, measures that may not pass the TRC test in a "typical" or "average" application often will pass in niche applications. Air sealing and insulation in older homes (build before 1980) is one example that was included in this study, because the available data permitted an estimate of the higher heat loss in these older homes. Similarly, additional domestic hot water measures may be feasible in homes with a larger number of occupants. For example, drain water heat recovery systems and DHW recirculation systems become more economically attractive with larger household sizes. These latter measures have not been included in the current results as suitable data were not available.

- ***Market Transformation Approaches Warrant Additional Consideration:*** There remains an additional untapped potential savings by from technically mature measures that do not currently pass the TRC screen. The largest share of these additional potential savings is from air sealing and envelope insulation in existing homes. These measures do not pass the TRC screen as currently defined. However, they provide non-energy benefits such as increased comfort and reduced noise that are not currently captured in the TRC calculation. Similarly, industry specialists emphasized that as insulation levels increase, proper air and moisture sealing is becoming increasingly essential to the long-term

[138] Design of a DSM program portfolio is beyond the scope of this current study.

[139] Over time, it is also expected that some relatively new technologies, such as tankless water heaters and high-performance windows, may become less expensive as they gain greater sales volumes.

structural integrity of Ontario’s housing stock. This situation presents both an opportunity and a possible technical issue that may be better addressed through a market transformation approach.

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9. GLOSSARY

Achievable potential
The Achievable Potential is the proportion of the natural gas savings identified in the Economic Potential Forecast that could realistically be achieved within the study period. Achievable Potential recognizes that it is difficult to induce customers to purchase and install all of the efficiency technologies that meet the criteria defined by the Economic Potential Forecast.

Avoided cost
The unit cost of acquiring the next resource to meet demand, which is used as a measure for evaluating individual demand-side and supply-side options. In the context of this study "avoided cost" is the capital expenditure offset by Union Gas DSM activities (i.e., the cost of having to buy natural gas on the open market, contract for long-term supply, and/or build and run new storage/transmission facilities).

Base year
The Base Year is the year to which all potentials will be compared. It provides a detailed description of "where" and "how" natural gas is currently used in each sector. For this study, it is the calendar year 2007. The modelled base year energy use is calibrated against Union's actual sales for 2007.

Benefit/cost ratio
The measure benefit/cost ratio indicates the relative attractiveness of the measures. A measure that has a benefit/cost ratio in excess of 1.0 has benefits which outweigh its costs. Similarly, a measure with a benefit/cost ratio that is well in excess of one (e.g., 3.0) means that it is very attractive. A measure with a benefit/cost ratio of less than 1.0 has costs which outweigh its benefits.

Building envelope
The material separation between the interior and the exterior environments of a building. The building envelope serves as the outer shell to protect the indoor environment as well as to facilitate its climate control.

Co-generation
The simultaneous production of electric or mechanical energy and useful heat energy from a single fuel source.

Combustion efficiency
The ratio of energy released during combustion to the potential chemical energy available in the fuel.

Demand-side management (DSM)
Actions that modify customer demand for natural gas and that can defer the need for additional new supply.

Discount rate
The interest rate used in calculating the present value of expected yearly benefits and costs.

Economic efficiency
Allocation of human and natural resources in a way that results in the greatest net economic benefit, regardless of how benefits and costs are distributed within society.

Economic potential forecast
The economic potential forecast is an estimate of the level of natural gas consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost effective from society's perspective. All of the energy-efficiency technologies and measures that have a positive measure TRC are incorporated into the economic potential forecast. These technologies and measures are applied at either natural stock turnover rates or at designated years for immediate application.

Effective measure life (EML)
The estimate median number of years that the measures installed under a program are still in place and operable. EML incorporates field conditions, obsolescence, building remodelling, renovation, demolition and occupancy changes.

Energy audit
An on-site inspection and cataloguing of energy using equipment/buildings, energy consumption and the related end-uses. The purpose is to provide information to the customer and the utility. Audits are useful for load research, for DSM program design and for identification of specific energy savings projects.

Energy conservation
Activities by energy users that result in a reduction of the energy used to provide services. Energy conservation can include a wide variety of behavioural or operational changes that result in energy savings. For the purpose of this study, only energy savings achieved through physical or hardware installations are considered.

Energy intensity
The ratio of energy consumed per application or end use. For example, gigajoules per square metre of heated office space per day, or gigajoules per tonne of aluminum produced. All else being equal, energy intensity increases as energy efficiency decreases.

Emerging technologies
New energy-conserving technologies that are not yet market-ready, but may be market-ready over next 5 to 10 years. This category includes technologies that could be accelerated into the market during that period through targeted financial or technical support.

End use
The final application or final use to which energy is applied. End use is often used interchangeably with energy service.

Energy savings
The savings that result from efficient technologies or activities. In this document, the term "energy" refers specifically to energy derived from natural gas unless otherwise noted.

Energy service
An amenity or service supplied jointly by energy and other components/equipment such as buildings and heating equipment. Examples of energy services include residential space heating, commercial cooking, aluminum smelting and public transit. The same energy service can frequently be supplied with different mixes of equipment and energy.

Energy use index (EUI)
End use energy consumption divided by a specific parameter of production (e.g., MJ/m^2., MJ/unit).

Environmental credit/environmental penalty
An increment or decrement to the cost of a resource or set of resources, to reflect the overall level of its/their environmental impact, relative to another resource or set of resources.

Financial incentive
Certain financial features in the utility's DSM programs designed to motivate customer participation. They may include features designed to reduce a customer's net cash outlay, pay-back period or cost of finance to participate.

Fuel share
The proportion of requirements for a specific service met using a certain fuel. For example, a natural gas fuel share of 90% for space heating in commercial large office sub sector implies that 90% of the sub sector floor space is heated using natural gas. Similarly, a 90% natural gas fuel share in single family detached homes means that 90% of the space heating requirements for that dwelling type are met by natural gas.

Gigajoule
One billion joules or one thousand megajoules.

Interactive effects
In the context of natural gas use, interactive effects refer to the increase in gas consumed by heating equipment required to offset a decrease in "waste" heat generated by more efficient electrical fixtures or appliances after retrofit or replacement.

Joule
The basic unit of energy. In physical terms, equal to the work required to move a mass of one Newton a distance of one metre.

Kilowatt (kW)
One thousand watts; the most common unit of measurement of electric power. (The amount of energy transferred at a rate of one kilowatt for one hour is equal to one kilowatt hour.)

Kilowatt hour (kWh)
The most common unit of measurement of electric energy. One kilowatt hour represents the power of one thousand watts for a period of one hour.

Load forecast
An estimate of expected natural gas requirements that have to be met by the utility in future years.

Load research
Research to disaggregate and analyze patterns of natural gas consumption by various subsectors and end-uses. Load Research supports the development of the load forecast and the design of demand-side management programs.

Measure total resource cost (TRC)
The Measure TRC is the net present value of energy savings that result from an investment in a energy efficiency measure. The Measure TRC is equal to its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy and operating & maintenance costs. This calculation includes among others, the following inputs: the avoided natural gas and electricity supply costs; the life of the measure; and the selected discount rate.

Megajoule
One million joules.

Natural conservation
The future change in energy intensity that is expected to occur in the absence of utility DSM programs.

Non-participant test (NPT)
A test measuring what happens to rates due to changes in utility revenues and operating costs caused by a program. Rates will go down if the avoided cost is greater than the sum of the revenue lost plus the program costs. This test indicates the direction and magnitude of the expected change in rate levels.

Rate
Generically refers to a utility's rate structure.

Rate structure
The formulae used by a utility to calculate charges for the use of natural gas or electricity.

Reference case forecast
An estimate of the expected level of natural gas consumption that would occur over the study period in the absence of any new utility DSM market interventions after 2008. It is the baseline against which the scenarios of energy savings are calculated. The Reference Case forecast incorporates an estimation of "natural conservation," namely, changes in end-use efficiency over the study period that are projected to occur in the absence of new market interventions by the utility.

Saturation
The portion of floor area that receives a specific energy service. For example, a saturation of 86% for space cooling in the Large Office sub sector means that 86% of the sub sector floor space is cooled (regardless of fuel used to provide that cooling).

Seasonal efficiency
The ratio of delivered useful energy relative to the input potential fuel energy determined over a full heating season (or year).

Sector
A group of customers having a common type of economic activity. Union Gas divides its customers into three principal sectors: Residential, Commercial and Industrial. Sectors are further divided into subsectors. For example, “Large Offices” is a sub sector of the Commercial sector.

Service area
The portion of the Province of Ontario that receives service from Union Gas. Union Gas’ service area is spread across the Province of Ontario including northern, southwestern and southeastern cities and towns.

Service region
For the purposes of this study, the total Union Gas service area is divided into two service regions. They are the Northern Region and Southern Region.

Simple payback
The simple payback is generated to show the customer’s financial perspective. Simple payback is a measure of the length of time required for the cumulative savings from a project to recover its initial investment cost and other accrued costs, without taking into account the time value of money.

Strategic conservation
Utility action to reduce the total natural gas demand. Strategic conservation is natural gas conservation induced by utility programs.

Strategic load growth
Utility action to increase (annual) total natural gas demand for specific end uses.

Sub sectors
A classification of customers within a sector by common features. Residential subsectors are by type of home (SFD, duplex, apartment, etc.). Commercial subsectors are generally by type of commercial service (office, retail, warehouse, etc.). Industrial subsectors are by product type (pulp and paper, solid wood products, chemicals, etc.).

Supply curves
A curve illustrating the amount of energy available at an appropriate screened price in ascending order of cost.

Total Resource Cost (TRC) Test
A test that compares the total costs of energy efficiency investments, including natural gas conservation programs, to the social cost of natural gas. Un-priced environmental and social costs may be accounted for by changing the cost of either the investment under consideration or the total cost of natural gas in such a way that relative un-priced impacts are reflected. It is used in designing and evaluating programs that are developed from the Energy Efficiency Potential study's results.

Utility cost
The total financial cost incurred by the utility to acquire energy resources. For DSM, the costs include all utility program costs, including incentive costs.

Watt
The basic unit of measurement of power.

Natural Gas
Energy Efficiency Potential

Commercial Sector

–Final Report–

Submitted to:

Union Gas

Submitted by:

Marbek Resource Consultants Ltd.

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Note to Reader

The primary economic data for this study was compiled during the period April to June of 2008. They represented the best available at the time. However, since that time, Canada and other global economies have entered a period of unprecedented economic uncertainty that may have significant impact on the results of this study, particularly in the short term. Three elements that affect this study's results are particularly impacted by these economic changes:

- Sector growth rates
- DSM Program participation rates that are used to determine the estimates of achievable potential
- Type of DSM investment

Sector Growth Rates

Key factors underlying Union's load forecast and the study's Reference Case such as gross domestic product (GDP), energy prices, commodity prices, currency values etc. are expected to change under the current conditions. The impact of these changes, at least in the short term, is expected to be reduced industrial output accompanied by reduced consumption of natural gas. At this time, it is impossible to predict either the extent or the duration of the economic downturn and its consequent impact on natural gas consumption.

DSM Program Participation Rates

The participation rates estimated during the Achievable Potential workshops do not explicitly take into account changes in industry outlook as a result of the economic downturn. In the short term, the expected impact would be lower discretionary investment and, hence, lower program participation rates than those presented in this report. As neither the extent nor the duration of the economic downturn is known at this time, it is not possible to estimate the total reduction in program participation rates over the full study period.

Type of DSM Investment

Many of the DSM investments included in this study's results pass the economic screen on a full cost basis and can be implemented at any time over the study period. This means that even if program participation rates are reduced in the short term, there remains the possibility of recapturing some of these opportunities in later portions of the study period. However, some of the DSM investment opportunities included in the study's results occur only when existing equipment is replaced at the end of its life. This means that if program participation rates are reduced in the short term, then the opportunity to implement the energy efficient model is lost until the equipment again comes up for replacement, which in most applications will be beyond the period covered by this study.

EXECUTIVE SUMMARY

❑ Background and Objectives

Union Gas Ltd. (Union) is a natural gas utility serving almost 1.3 customers in the residential, commercial and industrial markets. Union is a regulated utility with a Service area spread across the Province of Ontario including Northern, southwestern and southeastern cities and towns. Union distributes approximately 13.88 billion cubic metres (489.91 billion cubic feet) of natural gas to its customers annually.

Since 1997, Union has delivered demand side management (DSM) programs to its customers under a mandate from the provincial regulator, the Ontario Energy Board (OEB). Union offers DSM programs to all in-franchise customer rate classes and across all sectors and the DSM savings target and budget are determined through a rate proceeding with the OEB. Over the past eleven years Union has delivered approximately 614 million m^3 of natural gas savings and over $1 billion in net Total Resource Cost (TRC) benefits.

Union has been participating in a market of increasing DSM program maturity. This market is continually evolving in its engagement with energy efficiency through growing voluntary initiatives and more stringent codes and standards. In addition, changes in the economy have started to show signs of negatively impacting the commercial and industrial marketplace in Union's Service Area.

In the DSM Generic Proceeding held in 2006, Union committed to creating an updated Market Potential Study for input into the next DSM plan. This study will support the identification of potential energy savings for Union's next multi-year plan and be part of Union's regulatory filing in the next DSM rate case.

Union has initiated this current study within the context of the conditions noted above. When completed, the results of this natural gas Efficiency Potential Study will provide a foundation that Union can use to guide the development of its longer-term DSM strategy, including new measures and targets. More specifically, this includes support for Union's filing to the OEB regulatory application for the next multi-year DSM plan by:

- Estimating the achievable and economic potential for DSM measures across all applicable technologies, markets and sectors in Union's Service Area
- Giving shape to, and refining, ongoing energy-efficiency work by Union in order to develop its next multi-year DSM plan, and
- Provide information that is actionable and can be easily converted to plan and program development.

❑ Scope and Organization

This study covers a 10-year study period from 2007 to 2017 and addresses the Residential, Commercial and Industrial sectors. The 2007 calendar year was selected as the Base Year as this is the most recent year for which complete customer data are available.

The study addresses the full range of natural gas efficiency measures. Results are presented for the total Union Service Area and for two service regions: Southern and Northern. The Southern region of Union's system extends through Southwestern Ontario from Windsor to just west of Toronto. The Northern region of Union's system extends throughout Northern Ontario from the Manitoba border to the North Bay/Muskoka area and across Eastern Ontario from Port Hope to Cornwall. The study results are disaggregated by service region due to differences in building stock and weather conditions (heating degree days).

This report presents the results for Union's Commercial sector[1]

❑ Approach

The detailed end-use analysis of the Commercial sector was conducted using two linked modeling platforms: **CEEAM** (Commercial Energy and Emissions Analysis Model), Marbek's in-house commercial building stock energy-use simulation model, and **CSEEM** (Commercial Sector Energy End-use Model), a Marbek in-house spreadsheet-based macro model. The models are described in further detail in Section 1.

The major steps involved in the analysis are shown in Exhibit ES1 and are discussed in greater detail in Section 1. As illustrated in Exhibit ES1, the results of this study, and in particular the estimation of Achievable Potential,[2] support Union's on-going DSM program planning; however, it should be emphasized that the estimation of Achievable Potential is not synonymous with either the setting of specific targets or with detailed program design, which are beyond the scope of this study.

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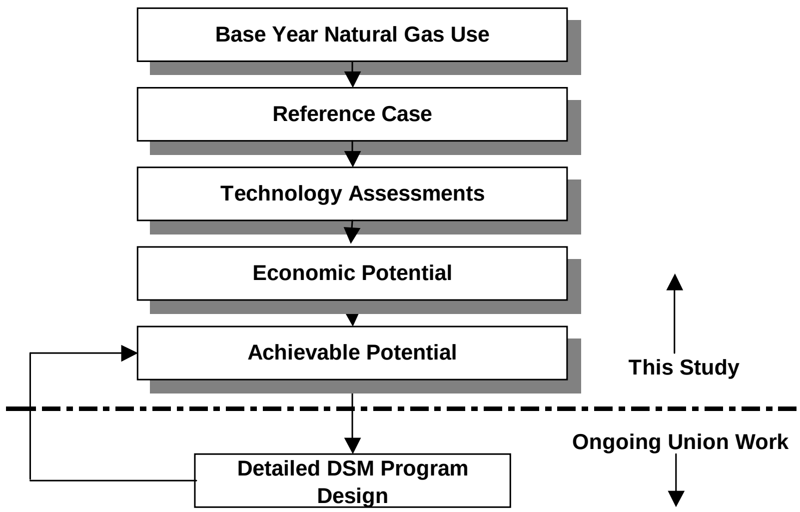
[1] The sub sectors Other Buildings and Other Contract Institutional Buildings are included in the total load but natural gas consumption was not modeled by end use in these sub sectors.

[2] The proportion of savings identified that could realistically be achieved within the study period, under various program spending and market conditions.

Exhibit ES1: Study Approach - Major Analytical Steps



❑ Overall Study Findings

As in any study of this type, the results presented in this report are based on a large number of important assumptions. Assumptions such as those related to the current penetration of energy-efficient technologies, the rate of future growth in the province's building stock and customer willingness to implement new efficiency measures are particularly influential. Wherever possible, the assumptions used in this study are consistent with those used by Union and are based on best available information, which in many cases includes the professional judgement of the consultant team, Union personnel and local experts. The reader should, therefore, use the results presented in this report as best available estimates; major assumptions, information sources and caveats are noted throughout the report.

The study findings confirm the existence of significant cost-effective DSM potential in Union's Commercial sector. Efficiency improvements within the Union service area would provide between 390 and 259 million m^3/yr. of natural gas savings by 2017 in, respectively, the Financially Unconstrained and the Static Marketing Achievable scenarios. The most significant Achievable Savings opportunities were actions that reduce space heating loads in existing buildings (e.g., building recommissioning, advanced Building Automation Systems, and space heating equipment upgrades), and actions that reduce water heating loads in existing buildings, including low flow fixtures and water heating equipment upgrades.

Although program costs for the Financially Unconstrained and the Static Marketing scenarios will vary depending on the specific composition of the future program portfolio, both scenarios show an evident trend towards higher future costs to achieve natural gas savings and TRC benefits.[3] This trend recognizes that savings from DSM programs tend to become more

[3] Design of a DSM program portfolio is beyond the scope of this current study.

expensive with time as the most attractive measures gain greater market penetration and only the more challenging measures remain.[4]

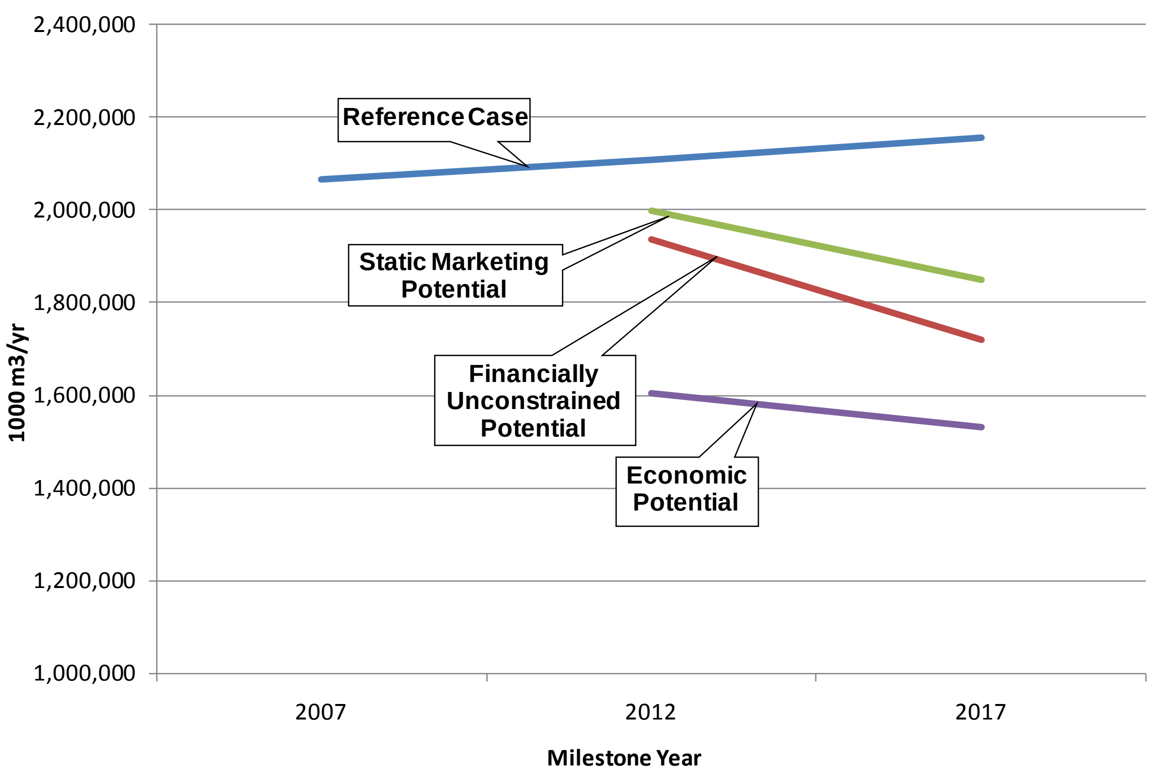
❑ Summary of Natural Gas Savings

A summary of the levels of annual natural gas consumption contained in each of the forecasts addressed by the study is presented by milestone year in Exhibits ES2 and ES3, and discussed briefly in the paragraphs below.

Exhibit ES2: Summary of Forecast Results for the Total Union Service Area – Annual Natural Gas Consumption, Commercial Sector (1000 m^3/yr.)

Annual Consumption (1000 m^3/yr.) Commercial Sector					Potential Savings (1000 m^3/yr.)		
Milestone Year	Reference Case	Economic	Achievable		Economic	Achievable	
			Unconstrained	Static		Unconstrained	Static
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2007	2,067,064						
2012	2,110,220	1,605,716	1,937,890	1,997,612	504,505	172,330	112,609
2017	2,157,072	1,531,696	1,720,144	1,851,019	625,376	390,076	259,202

Exhibit ES3: Graphic of Forecast Results for the Total Union Service Area – Annual Natural Gas Consumption, Commercial Sector (1000 m^3/yr.)



[4] Over time, it is also expected that some relatively new technologies, such as tankless water heaters and super high-performance glazings, may become less expensive as they gain greater sales volumes.

Base Year Natural Gas Use

Exhibit ES4 shows that in the Base Year of 2007, Union's Commercial sector consumed about 2,067 million m^3 of natural gas.

Exhibit ES4: Base Year Natural Gas Use by End Use for the Total Union Service Area, Commercial Sector

Sub Sector	Space Heating	Water Heating	Cooking	Space Cooling	Other	Total
Large Office	99,744	7,774	324	185	11,716	119,743
Small Office	213,790	15,367	626	0	12,519	242,302
Retail	147,344	9,583	4,219	0	5,274	166,419
Large Hotel	7,649	4,766	643	0	919	13,978
Small Hotel/Motel	4,849	2,718	59	0	588	8,214
Contract Hospital	41,177	10,879	1,096	291	7,026	60,469
Hospital	18,650	3,762	489	70	1,361	24,332
Nursing Home	42,669	12,719	2,843	0	4,045	62,276
School	127,355	7,415	1,783	0	841	137,394
Contract University/College	58,582	10,173	2,868	617	7,170	79,409
University/College	12,355	1,837	444	118	846	15,600
Restaurant/Food Service	39,992	15,664	25,853	0	326	81,836
Warehouse	61,965	3,307	138	0	2,752	68,162
Contract Apartment	5,038	1,854	22	0	179	7,093
High-rise Apartment	120,369	40,913	522	0	4,176	165,980
Mid-rise Apartment	74,936	24,848	484	0	1,210	101,478
Other Buildings						391,810
Other Contract Institutional Buildings						320,568
Total	1,076,463	173,581	42,413	1,280	60,948	2,067,064

Note: Any difference in totals is due to rounding.

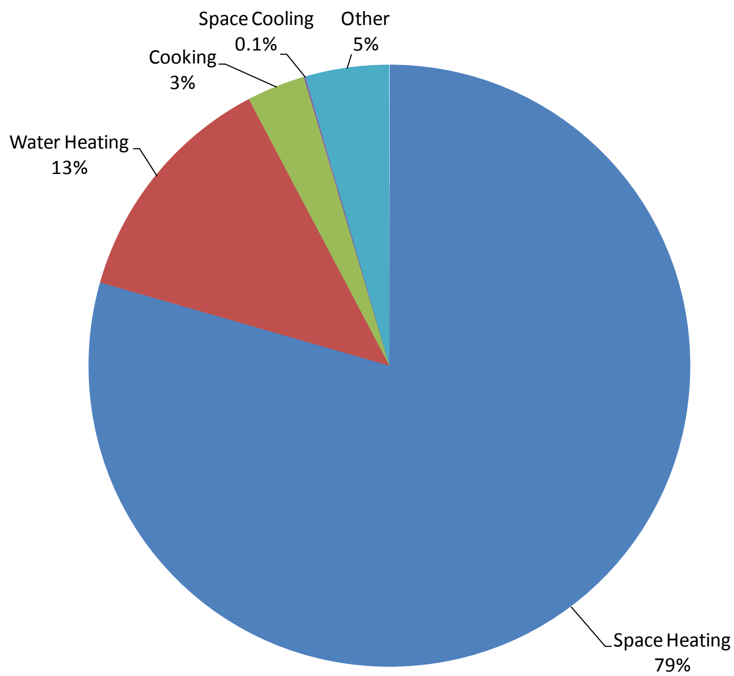


Exhibit ES4 also shows that space heating accounts for about 79% of total commercial natural gas use. Water heating accounts for about 13% of the total natural gas use, followed by cooking at 3%. The remaining 5% of natural gas consumption in the Commercial sector occurs in a variety of other applications, such as dehumidification, air reheat, steam distribution losses, laboratory equipment, laundry equipment and space cooling.

The sub sectors Other Buildings and Other Contract Institutional Buildings have the largest share of total gas consumption at 19% and 16% respectively. Among modelled sub sectors, Small Office accounts for 12% of total gas consumption, followed by Retail and High-rise Apartment at 8% each.

The Southern service region accounts for 77% of the commercial natural gas consumption in the total Union Service Area.

Reference Case

In the absence of new Union DSM initiatives, the study estimates that natural gas consumption in Union's Commercial sector will grow from 2,067 million m^3 in 2007 to about 2,157 million m^3 by 2017. This represents an overall growth of about 2.2 % in the period and compares very closely with Union's load forecast. Both this study and the Union load forecast include consideration of the impacts of "natural conservation."

Economic Potential Forecast

Under the conditions of the Economic Potential Forecast,[5] the study estimated that natural gas consumption in Union's Commercial sector would decline from the Base Year levels of 2,067 million m^3 to about 1,531 million m^3 by 2017. Annual savings relative to the Reference Case are 626 million m^3, or about 29%.

Achievable Potential

As noted above, the Achievable Potential is the proportion of the economic natural gas savings that could be realistically achieved within the study period under various program spending and marketing conditions.

Under the conditions defined by the Financially Unconstrained scenario, total Commercial sector natural gas savings in 2017 are estimated to be approximately 390 million m^3/yr. This represents a saving of approximately 18%, relative to the Reference Case and is equal to approximately 62% of the savings identified in the Economic Potential Forecast.

Under the conditions defined by the Static Marketing scenario, total Commercial sector natural gas savings in 2017 are estimated to be approximately 259 million m^3/yr. This represents a saving of approximately 12%, relative to the Reference Case and is equal to approximately 41% of the savings identified in the Economic Potential Forecast.

[5] The level of natural gas consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost effective. In this study, "cost effective" means that the technology upgrade passes the measure TRC test.

The most significant Achievable Savings opportunities were actions that reduce space heating loads in existing buildings (e.g., building recommissioning, advanced building automation systems, space heating equipment upgrades and heat recovery), and actions that reduce hot water loads in existing buildings, including low-flow fixtures and water heating equipment upgrades. Building recommissioning is a particularly large opportunity.

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1. INTRODUCTION

1.1 BACKGROUND AND OBJECTIVES

Union Gas Ltd. (Union) is a natural gas utility serving almost 1.3 customers in the commercial, commercial and industrial markets. Union is a regulated utility with a Service Area spread across the Province of Ontario including northern, southwestern and southeastern cities and towns. Union distributes approximately 13.88 billion cubic metres (489.91 billion cubic feet) of natural gas to its customers annually.

Since 1997, Union has delivered demand side management (DSM) programs to its customers under a mandate from the provincial regulator, the Ontario Energy Board (OEB). Union offers DSM programs to all in-franchise customer rate classes and across all sectors and the DSM savings target and budget are determined through a rate proceeding with the OEB. Over the past eleven years Union has delivered approximately 614 million m^3 of natural gas savings and over $1 billion in net Total Resource Cost (TRC) benefits.

Union has been participating in a market of increasing DSM program maturity. This market is continually evolving in its engagement with energy efficiency through growing voluntary initiatives and more stringent codes and standards. In addition, changes in the economy have started to show signs of negatively impacting the commercial and industrial marketplace in Union's Service Area.

In the DSM Generic Proceeding held in 2006, Union committed to creating an updated Market Potential Study for input into the next DSM plan. This study will support the identification of potential energy savings for Union's next multi-year plan and be part of Union's regulatory filing in the next DSM rate case.

Union has initiated this current study within the context of the conditions noted above. When completed, the results of this natural gas Efficiency Potential Study will provide a foundation that Union can use to guide the development of its longer-term DSM strategy, including new measures and targets. More specifically, this includes support for Union's filing to the OEB regulatory application for the next multi-year DSM plan by:

- Estimating the achievable and economic potential for DSM measures across all applicable technologies, markets and sectors in Union's Service Area
- Giving shape to, and refining, ongoing energy-efficiency work by Union in order to develop its next multi-year DSM plan, and
- Provide information that is actionable and can be easily converted to plan and program development.

1.2 STUDY SCOPE

The scope of this study is summarized below.

- **Sector Coverage:** The study addresses three sectors: Residential, Commercial[6] and Industrial.

- **Geographical Coverage**: The study results are presented for the total Union Service Area and for two service regions: Southern and Northern. The Southern region of Union's system extends through Southwestern Ontario from Windsor to just west of Toronto. The Northern region of Union's system extends throughout Northern Ontario from the Manitoba border to the North Bay/Muskoka area and across Eastern Ontario from Port Hope to Cornwall. The study results are further disaggregated by service region due to differences in building stock and weather conditions (heating degree days).

- **Study Period**: This study covers a 10-year period. The Base Year is the calendar year 2007, with milestone periods at five-year increments: 2012 and 2017. The Base Year of 2007 was selected as this was the most recent calendar year for which complete customer data were available.

- **Technologies:** The study addresses the full range of natural gas energy-efficiency measures (see Exhibit 1.1, overleaf).

1.2.1 Data Caveat

As in any study of this type, the results presented in this report are based on a large number of important assumptions. Assumptions such as those related to the current penetration of energy-efficient technologies, the rate of future growth in Union's industrial load and customer willingness to implement new energy-efficiency measures are particularly influential.

Wherever possible, the assumptions used in this study are consistent with those used by Union and are based on best available information, which in many cases includes the professional judgment of the consultant team, Union personnel and/or local experts. The reader should use the results presented in this report as best available estimates; major assumptions, information sources and caveats are noted throughout.

[6] Throughout this report the term "Commercial" also includes institutional sectors, such as schools, hospitals, etc., unless otherwise noted.

Exhibit 1.1: Commercial Energy-efficiency Technologies

Building Envelope and HVAC	Domestic Hot Water, Cooking and Whole Building
Building Envelope: • High-Performance Glazings • Super High-Performance Glazings • Wall Insulation Upgrade • Roof Insulation Upgrade • Air Sealing • Air Curtains • Vinyl Strip Curtains • Fast-moving Doors • L-Shaped Vestibules • Turnstile Doors **Heating, Ventilating and Air-Conditioning:** • Condensing Boilers • Near-Condensing Boilers • Condensing Unit Heaters • High-Efficiency Rooftop Units • Condensing Rooftop Units • Absorption Heat Pumps • Steam Plant Efficiency Measures • HVLS De-stratification Fans • Heat Reflector Panels • Programmable Thermostats • Heat Recovery • Demand Controlled Ventilation • Demand Control Kitchen Ventilation • Furnace & Boiler Tune-ups • Condensing Furnaces • Infrared Heaters • Solar Preheated Make-up Air	**Domestic Hot Water:** • Condensing Water Heaters • Condensing Tank-Type Water Heaters • Tankless Water Heaters • Drainwater Heat Recovery • Low-Flow Faucet Aerators & Showerheads • Low-Flow Pre-Rinse Spray Valves • Solar Water Heating • Booster Water Heaters **Cooking:** • Efficient Griddles • Efficient Broilers • Efficient Ovens • ENERGY STAR® Fryers **Whole Building:** • Building Recommissioning • Advanced Building Automation Systems • High-Performance New Building Construction • Includes high-efficiency building envelopes, space heating & ventilation equipment, water heating equipment, food preparation equipment, whole building measures, LEED building criteria and specific technologies and practices such as multi-unit residential patio beam insulation, green roofs and cellular concrete.

1.3 DEFINITIONS[7]

This study employs numerous terms that are unique to analyses such as this one and consequently it is important to ensure that readers have a clear understanding of what each term means when applied to this study. Below is a brief description of some of the most important terms.

Base Year Natural Gas Use — The Base Year is the starting point for the analysis. It provides a detailed description of "where" and "how" natural gas is currently used in the Commercial sector. The bottom up profile of energy use patterns and market shares of energy-using technologies was calibrated to actual Union customer sales data.

[7] A Glossary is provided in Section 9.

Reference Case Forecast The Reference Case is a projection of natural gas consumption to 2017, in the absence of any new Union DSM market interventions after 2008. It is the baseline against which the scenarios of energy savings are calculated. The Reference Case forecast incorporates an estimation of "natural conservation," namely, changes in end-use efficiency over the study period that are projected to occur in the absence of new market interventions by Union.

Measure Total Resource Cost The measure TRC calculates the net present value of natural gas, electricity and water savings that result from an investment in an efficiency technology or measure. The measure TRC is equal to its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy, water and equipment operating and maintenance (O&M) costs. This calculation includes, among others, the following inputs: the avoided natural gas, electricity and water supply costs, the life of the technology and the selected discount rate, which in this analysis has been set at 10%.

The measure TRC test is the primary determinant of whether a measure is included in the economic potential.

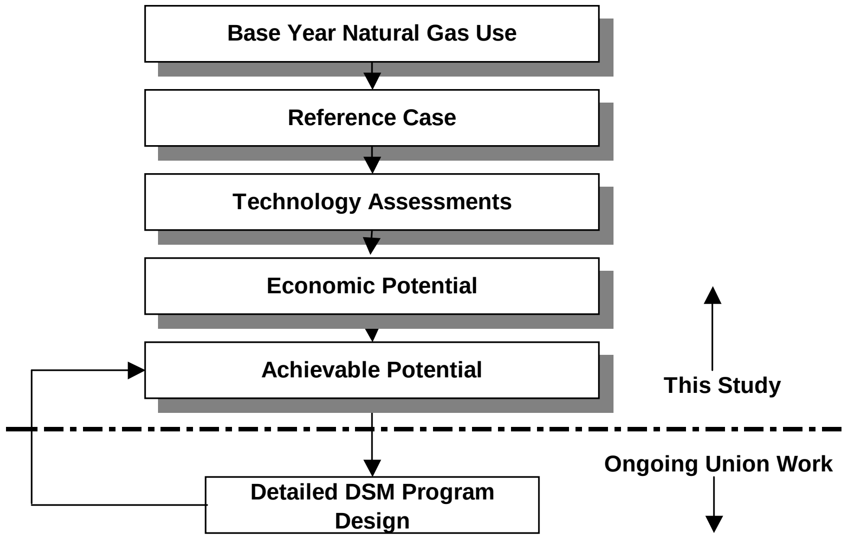
Economic Potential Forecast The Economic Potential Forecast is the level of natural gas consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost effective from Union's perspective. All of the energy-efficiency technologies and measures that have a positive measure TRC are incorporated into the Economic Potential Forecast. These technologies and measures are applied at either natural stock turnover rates or at designated years for immediate application.

Achievable Potential The Achievable Potential is the proportion of the natural gas savings identified in the Economic Potential Forecast that could realistically be achieved within the study period. Achievable Potential recognizes that it is difficult to induce customers to purchase and install all of the efficiency technologies that meet the criteria defined by the Economic Potential Forecast.

1.4 APPROACH

To meet the objectives outlined above, the study was conducted within an iterative process that involved a number of well-defined steps. At the completion of each step, the client reviewed the results and, as applicable, revisions were identified and incorporated into the interim results. The study then progressed to the next step. A summary of the steps is presented in Exhibit 1.2 and briefly discussed below.

Exhibit 1.2: Major Study Steps



Step 1: Develop Profile of Base Year Natural Gas Use

- Compile and analyze available data on Union's existing building stock, including both customer billing data and information from customer surveys, facility energy audits etc.
- Develop detailed technical descriptions of the existing building stock for each sub sector and service region
- Compile actual Union billing data
- Undertake computer simulations of energy use in each building sub sector and compare these with actual building billing and audit data
- Calibrate sector model results using actual Union billing data.
- The output of Step 1 forms Section 2 of this report.

Step 2: Develop Reference Case Forecast for the Study period

- Compile and analyze building design, equipment and operations data and develop detailed technical descriptions of the new building stock
- Develop computer simulations of energy use in each new building sub sector
- Compile data on forecast levels of building stock growth and "natural" changes in equipment efficiency levels and/or practices
- Define sector model inputs and create forecasts of energy use for each of the milestone years
- Compare sector model results with Union's forecast for the period.
- The output of Step 2 forms Section 3 of this report.

Step 3: Develop and Assess Energy-efficiency Upgrade Options

- Develop list of energy-efficiency measures in consultation with the client
- Compile detailed cost and performance data for each measure
- Assess the energy, WATER and economic impacts of implementing the energy-efficiency upgrade options in place of the baseline technologies employed in the Reference Case
- Determine the measure TRC for each upgrade option.

- The output of this task forms Section 4 of this report.

Step 4: Estimate Economic Energy Savings Potential

- Compile utility economic data on the forecast cost of new natural gas supply;
- Screen the identified energy-efficiency upgrade options from Step 3 against the utility economic data
- Identify the combinations of energy-efficiency upgrade options and building types where the measure TRC is positive
- Apply the economically attractive efficiency measures from Step 3 within the energy use simulation model developed previously for each building type
- Determine annual energy consumption in each building type when the economic efficiency measures are employed
- Compare the energy consumption levels when all economic efficiency measures are used with the Reference Case consumption levels and calculate the energy savings.
- The output of this task forms Section 5 of this report.

Step 5: Estimate Achievable Energy Savings Potential

- "Bundle" the energy saving opportunities identified in the Economic Potential Forecast into a set of Actions
- Create "Action Profiles" for each of the identified Actions that provide a "high-level" rationale and direction, including target technologies and sub-markets as well as key barriers and a broad intervention strategy
- Review historical achievable program results and prepare preliminary Action Assessment Worksheets
- Conduct Achievable Potential workshops involving utility and consultant team personnel, selected trade allies and technology and market experts to reach general agreement on a range of Achievable Potential based on different funding scenarios
- The output of this task forms Section 6 of this report.

1.5 ANALYTICAL MODELS

The detailed end-use analysis of the Commercial sector was conducted using two linked modeling platforms as follows:

- ***CEEAM*** (***C***ommercial ***E***nergy and ***E***missions ***A***nalysis ***M***odel), an in-house, simulation model, developed in conjunction with Natural Resources Canada for modeling energy use in commercial/institutional building stock.
- ***CSEEM (C***ommercial ***S***ector ***E***nergy ***E***nd-use ***M***odel), an in-house spreadsheet based macro model.

CEEAM is Marbek's in-house model used to develop commercial natural gas end-use intensities (EUIs) for each of the commercial and institutional building archetypes. CEEAM has been successfully employed in numerous studies for NRCan, several electric and natural gas utilities and international DSM projects, including the extensive national climate change analysis conducted for the Federal Buildings Table. CEEAM is a robust modeling platform and its results have been verified against actual end-use metered data for the cities of Ottawa and Toronto and against DOE-2.1E.

CEEAM has been developed specifically for applications such as this study. One of CEEAM's particular strengths is the capability to simulate energy performance not only in a given building but also in an entire stock of similar buildings (e.g., all Large Offices). In particular, it is capable of tracking the penetration of multiple technologies and combinations that are not possible in other simulation software, such as DOE 2.

CEEAM simulates the energy consumption for all natural gas end uses present in a given commercial building segment. CEEAM calculates energy use and emissions by end use and reports them in $MJ/m^2/yr.$ and kg eCO_2/m^2. Because CEEAM is a full modeling program, it calculates both building heating and cooling loads (internal and transmission), thus accounting for interactive effects such as the increase in heating use and decrease in cooling electricity use from lighting retrofits. CEEAM also uses equipment part load performance curves to accurately model the seasonal efficiency of heating and cooling plants.

The EUIs derived by CEEAM provide inputs into CSEEM (Marbek's in-house Commercial Sector Electricity End-use Model). As noted above, CSEEM is a spreadsheet-based macro model. It consists of two modules:

- A General Parameters module that contains general sector data (e.g., total building stock floor area per sub sector, growth rates, etc.)
- A Building Profile module that contains the EUI data for each of the selected building segments.

CSEEM combines the data from each of the modules and provides total natural gas use by service region, building sub sector and end use.

1.6 THIS REPORT

This report addresses the Commercial sector and provides a summary of the results to date. This report is presented in the following sections.

- Section 2 presents a profile of Base Year Natural Gas use in Union's Service Area, including a discussion of the major steps involved and the data sources employed.

- Section 3 presents the Commercial sector Reference Case for the study period 2007 to 2017.

- Section 4 provides a financial and economic assessment of the identified energy-efficiency measures.

- Section 5 presents the Commercial sector Economic Potential Forecast for the study period 2007 to 2017.

- Section 6 presents the estimated range of Achievable Potential for natural gas savings, under differing scenarios, for the study period 2007 to 2017.

- Section 7 presents the conclusions.

- Section 8 presents a listing of major references.
- Section 9 provides a glossary of commonly used terms.

2. BASE YEAR NATURAL GAS USE

2.1 INTRODUCTION

This section presents a description of natural gas use in Union's Commercial sector in the Base Year of 2007. Drawing on the best available data, this section presents total natural gas consumption in Union's Commercial sector, together with an estimate of how that consumption is distributed by service region, sub sector and end use.

The remainder of this section outlines the steps involved in preparing the profile of Base Year natural gas use and presents a summary of the results. The discussion is organized into the following subsections:

- Segmentation of Commercial Building Stock
- Segmentation of Union's Sales Data
- Development of Detailed Technical Profiles for Existing Buildings
- Derivation of Saturation and Fuel Share Data
- Summary of Base Year Natural Gas Use.

2.2 SEGMENTATION OF COMMERCIAL BUILDING STOCK

The first major task in developing the profile of Base Year natural gas use involved the segmentation of the commercial building stock into specific sub sectors. The choice of specific building sub sectors is driven by both data availability and the need to facilitate the subsequent analysis and modelling of potential energy-efficiency improvements. To facilitate the subsequent modelling and analysis of energy-efficiency opportunities, the selected building sub sectors need to be reasonably similar in terms of major design and operating considerations, such as building size, mechanical and electrical systems, annual operating hours, etc.

A summary of the Commercial sub sectors that are used in this study is provided in Exhibit 2.1.

Exhibit 2.1: Commercial Sub Sectors

- Large Office
- Small Office
- Retail
- Large Hotel
- Small Hotel/Motel
- Contract Hospital
- Hospital
- Nursing Home
- Contract University/College
- University/College
- School
- Restaurant/Food Service
- Warehouse
- Contract Apartment
- High-rise Apartment
- Mid-rise Apartment
- Other Buildings
- Other Contract Institutional Buildings

Selected additional information related to the sub sectors shown in Exhibit 2.1 is provided below.

Contract Sub sectors

These sub sectors include buildings served under contract agreements with Union including Hospitals, University/Colleges, Apartments and Other Contract Institutional Buildings. Included among the Other Contract Institutional Buildings sub sector are social service and correctional facilities.

Large and Small

Office and Hotel/Motel each have large and small sub sectors. The large sub sectors include buildings with an annual gas consumption of greater and 50,000 m^3; the small sub sectors include buildings with an annual gas consumption of less than 50,000 m^3.

Mid-rise and High-rise

The High-rise Apartment sub sector includes apartment and condominium buildings with an annual gas consumption of greater than 50,000 m^3. The Mid-rise Apartment sub sector includes apartment and condominium buildings with an annual gas consumption of less than 50,000 m^3.

Other Buildings

The Other Buildings sub sector includes all other buildings: recreational, religious, laundromats, gas stations/car washes and buildings classified in Union's customer database as other multi-family, other commercial and other institutional.

2.3 SEGMENTATION OF UNION CUSTOMER SALES DATA

Once agreement was reached on the selection and definition of the commercial sub sectors shown in Exhibit 2.1, Union compiled a summary of its total 2007 customer sales segmented into the selected sub sectors for each of the Southern and Northern service regions. The data were provided on both an annual and monthly basis.[8] A summary of the sales data mapping is provided below in Exhibit 2.2.

[8] Annual sales data were actual data and monthly sales data were derived using forecasting factors.

Exhibit 2.2: Sales Data Mapping

Study Sub sector	Union Sub sector Components
Large Office	Office Building >50,000 m^3 consumption
	Office Building Unit >50,000 m^3
Small Office	Office Building < 50,000 m^3
	Office Building Unit < 50,000 m^3
Retail	Retail Building
	Retail Plaza
	Retail Plaza Unit
Large Hotel	Hotel/Motel >50,000 m^3
Small Hotel/Motel	Hotel/Motel <50,000 m^3
Contract Hospital	Contract Institutional (Hospital Portion)
Hospital	Hospital Facility
Nursing Home	Senior/Nursing/Health Care
School	Education Primary/Secondary
	Permanent Daycare
Contract University/College	Contract Institutional (College/University Portion)
University/College	Education College/University
Restaurant/Food Service	Restaurant/Food Service
Warehouse	Warehouse Facility
Contract Apartment	Contract Apartment
High-rise Apartment	Apartment Building > 50,000 m^3
	Condominium Building > 50,000 m^3
	Apartment Unit > 50,000 m^3
Mid-rise Apartment	Apartment Building < 50,000 m^3
	Condominium Building < 50,000 m^3
	Apartment Unit < 50,000 m^3
Other Buildings	Commercial Other
	Recreation
	Religious
	Institutional Other
	Permanent Correctional Facility
	Commercial Laundromat
	Gas Station/Car Wash
	Multi-Family Other > 50,000 m^3
Other Contract Institutional Buildings	Other Contract Institutional Buildings

The actual sales data by sub sector provides the reference point for the calibration of the modelled results that were developed in subsequent steps of the analysis. This data was further disaggregated into its base and weather sensitive components to assist in the calibration. Base load factors for each sub sector were derived from Marbek's in-house database of end-use intensities for similar building types and service regions. This database is based on previous DSM project experience as well as several dozen commercial and institutional building audits. The database contains information on monthly gas sales data by for the Southern Ontario market at the sub sector level. Exhibit 2.3 presents a breakdown of the gas sales into base load and weather sensitive load components for each service region.

Exhibit 2.3: Natural Gas Sales by Component and Service Region[9]

Sub Sector	Southern service region				Northern service region			
	Total Sector Consumption (1000 m^3)	Estimated Base Load Proportion (%)	Base Load (1000 m3)	Weather Sensitive Load (1000 m3)	Total Sector Consumption (1000 m3)	Estimated Base Load Proportion (%)	Base Load (1000 m3)	Weather Sensitive Load (1000 m3)
Large Office	51,811	22%	11,398	40,413	67,931	21%	14,266	53,666
Small Office	90,394	14%	12,655	77,739	151,908	18%	27,343	124,565
Retail	150,327	14%	21,046	129,281	16,092	14%	2,253	13,839
Large Hotel	10,734	45%	4,830	5,904	3,243	45%	1,459	1,784
Small Hotel/Motel	5,854	50%	2,927	2,927	2,360	50%	1,180	1,180
Contract Hospital	53,461	40%	21,384	32,077	7,008	45%	3,154	3,855
Hospital	10,290	30%	3,087	7,203	14,042	40%	5,617	8,425
Nursing Home	41,142	38%	15,634	25,508	21,134	40%	8,454	12,681
School	87,245	7%	6,107	81,137	50,149	8%	4,012	46,137
Contract University/College	70,537	29%	20,456	50,081	8,872	29%	2,573	6,299
University/College	12,599	25%	3,150	9,449	3,001	30%	900	2,101
Restaurant/Food Service	71,838	60%	43,103	28,735	9,998	60%	5,999	3,999
Warehouse	64,300	8%	5,144	59,156	3,862	8%	309	3,553
Contract Apartment	7,093	29%	2,057	5,036	0	n/a	n/a	n/a
High-rise Apartment	149,737	27%	40,429	109,308	16,243	26%	4,223	12,020
Mid-rise Apartment	82,468	26%	21,442	61,027	19,010	25%	4,753	14,258
Other Buildings	340,457	20%	68,091	272,365	51,354	20%	10,271	41,083
Other Contract Institutional Buildings	295,028	20%	59,006	236,022	25,541	20%	5,108	20,433
Grand Total	1,595,315	24%	361,946	1,233,369	471,749	22%	101,873	369,876

2.4 FUEL SHARE DATA

The next step in the analysis involved an estimation of the gas fuel share[10] for space heating, water heating, space cooling and cooking. It is important to note that for the purposes of this study, the space heating end use includes the heating of make-up air and takes into account such factors as envelope losses and internal heat gains from electrical equipment. Various information sources were used to derive these estimates, including analysis of utility sales data, consultations with Union and local technical advisors, existing consultant team files of facility energy audits in Ontario facilities, reviews of previous Ontario sub sector specific analysis conducted by team members on behalf of a variety of clients and recent discussions with select building engineering practitioners. Unless specific data was available, natural gas fuel shares were assumed to be the same for the two regions.

Exhibit 2.4 presents the estimated fuel shares for each sub sector and service region.

[9] There are no contract apartment customers in the Northern service region.

[10] Refers to the percent of total load met by natural gas.

Exhibit 2.4: Natural Gas Fuel Share for Major End Uses by Sub Sector and Service Region (%)

Sub Sector	Southern service region			Northern service region		
	Space Heating	Water Heating	Cooking	Space Heating	Water Heating	Cooking
Large Office	90%	81%	20%	90%	81%	20%
Small Office	90%	81%	20%	90%	81%	20%
Retail	90%	66%	40%	90%	66%	40%
Large Hotel	65%	88%	50%	65%	88%	50%
Small Hotel/Motel	65%	85%	20%	65%	85%	20%
Contract Hospital	96%	82%	65%	96%	82%	65%
Hospital	96%	82%	65%	96%	82%	65%
Nursing Home	65%	90%	82%	65%	90%	82%
School	89%	77%	53%	89%	77%	53%
Contract University/College	83%	91%	70%	83%	91%	70%
University/College	83%	91%	70%	83%	91%	70%
Restaurant/Food Service	82%	82%	88%	82%	82%	88%
Warehouse	96%	64%	10%	96%	64%	10%
Contract Apartment	90%	79%	5%	n/a	n/a	n/a
High-rise Apartment	90%	79%	5%	90%	79%	5%
Mid-rise Apartment	90%	88%	10%	90%	88%	10%

2.5 DEVELOPMENT OF DETAILED TECHNICAL PROFILES FOR EXISTING BUILDINGS

The next step involved the development of detailed technical profiles for each of the major existing commercial building sub sectors described above.[11] Each profile contains detailed technical data on building envelope characteristics, hot water heating equipment, HVAC equipment, lighting systems, and cooking, plug and miscellaneous loads. The detailed technical profiles summarize the major data inputs that are used by Marbek's energy use simulation model to estimate natural gas use by sub sector and end use. It is important to note that Union sales data are based on customer accounts. For this reason, some accounts for mixed-use buildings are classified by their major use. For example, an office building with a ground floor retail store or restaurant would fall into one of the office sub sectors. These secondary uses are reflected in the sub sector technical profiles.

Development of the detailed building profiles was informed by existing consultant team files of facility energy audits in Ontario facilities, reviews of previous Ontario sub sector specific analysis conducted by team members on behalf of a variety of clients and recent discussions with select building engineering practitioners.

[11] Detailed building profiles were not constructed for the Other Buildings or Other Contract Institutional Buildings due to the wide variation of building types included in these sub sectors. Potential savings for the facilities included in these sub sectors will be estimated based on the results of the modelled sub sectors.

Separate building profiles were developed for each combination of sub sector and service region. Two representative weather regions were used as follows:

- Southern service region (London)
- Northern service region (North Bay)

A sample building profile summary for existing Large Offices in the Southern service region is presented in Exhibit 2.5. A complete set of detailed profiles for existing buildings are presented in Appendix A (Southern service region) and B (Northern service region).

Exhibit 2.5: Sample Building Profile Summary – Existing Large Office

Additional highlights are provided below related to each of the major Commercial sector natural gas end uses addressed by this study, namely:

- Space Heating
- Water Heating
- Cooking
- Space Cooling
- Other.

2.5.1 Space Heating

Model assumptions related to the distribution of natural gas space heating equipment are summarized in Exhibit 2.6.[12]

Exhibit 2.6: Space Heating Equipment Type - % of Natural Gas Heated Floor Area

Sub Sector	Southern service region		Northern service region	
	Boilers	Rooftop Units/ Other	Boilers	Rooftop Units/ Other
Large Office	50%	50%	50%	50%
Small Office	50%	50%	50%	50%
Retail	11%	89%	11%	89%
Large Hotel	80%	20%	80%	20%
Small Hotel/Motel	80%	20%	80%	20%
Contract Hospital	95%	5%	95%	5%
Hospital	95%	5%	95%	5%
Nursing Home	69%	31%	69%	31%
School	90%	10%	90%	10%
Contract University/College	76%	24%	76%	24%
University/College	76%	24%	76%	24%
Restaurant/Food Service	18%	82%	18%	82%
Warehouse	11%	89%	11%	89%
Contract Apartment	78%	22%	n/a	n/a
High-rise Apartment	78%	22%	78%	22%
Mid-rise Apartment	78%	22%	78%	22%

[12] Based on Marbek database and discussions with Union personnel.

2.5.2 Water Heating

Exhibit 2.7[13] presents the distribution of gas-fired water heating equipment between boilers and tank heaters that has been assumed in this study. The distributions are shown by sub sector and service region.

Exhibit 2.7: Existing Gas Water Heating Equipment Distribution - % of Floor Area Serviced by Gas-fired Water Heating

Sub Sector	Southern service region		Northern service region	
	Boilers	Tank Heaters	Boilers	Tank Heaters
Large Office	20%	80%	20%	80%
Small Office	5%	95%	5%	95%
Retail	3%	97%	3%	97%
Large Hotel	85%	15%	85%	15%
Small Hotel/Motel	74%	26%	74%	26%
Contract Hospital	87%	13%	87%	13%
Hospital	87%	13%	87%	13%
Nursing Home	76%	24%	76%	24%
School	40%	60%	40%	60%
Contract University/College	76%	24%	76%	24%
University/College	76%	24%	76%	24%
Restaurant/Food Service	17%	83%	17%	83%
Warehouse	9%	91%	9%	91%
Contract Apartment	30%	70%	n/a	n/a
High-rise Apartment	30%	70%	30%	70%
Mid-rise Apartment	20%	80%	20%	80%

13 Based on Marbek database and discussions with Union personnel.

2.5.3 Cooking

Exhibit 2.8[14] presents the natural gas cooking energy use intensities (EUIs) used in this study for each service region. These EUIs represent stock averages, which take into account the incidence of gas cooking equipment in each sub sector.

Exhibit 2.8: Gas Cooking EUIs (MJ/m^2.yr)

Sub Sector	Southern service region	Northern service region
Large Office	10	10
Small Office	10	10
Retail	40	40
Large Hotel	70	70
Small Hotel/Motel	30	30
Contract Hospital	60	60
Hospital	50	60
Nursing Home	60	60
School	20	20
Contract University/College	40	40
University/College	30	30
Restaurant/Food Service	900	900
Warehouse	10	10
Contract Apartment	50	n/a
High-rise Apartment	50	50
Mid-rise Apartment	40	40

2.5.4 Space Cooling

Natural gas space cooling represents a small proportion of the total space cooling end use as discussed in section 2.3. The gas-fired space cooling equipment present in the Union Service Area includes both gas engine-driven chillers and absorption chillers.

Exhibit 2.9 presents the estimates of space cooling saturation[15] and gas fuel share used in this study for each sub sector and service region.

[14] Based on Marbek database and discussions with Union personnel.

[15] Space cooling saturation refers to the percentage of the total floor space that is served by air conditioning equipment (both electricity and natural gas driven equipment).

Exhibit 2.9: Space Cooling Saturation and Fuel Share (% of Floor Space)

Sub Sector	Southern service region		Northern service region	
	Saturation	Natural Gas Fuel Share	Saturation	Natural Gas Fuel Share
Large Office	86%	1%	86%	0%
Small Office	86%	0%	86%	0%
Retail	85%	0%	85%	0%
Large Hotel	85%	0%	85%	0%
Small Hotel/Motel	85%	0%	85%	0%
Contract Hospital	75%	5%	75%	1%
Hospital	75%	5%	75%	1%
Nursing Home	60%	0%	60%	0%
School	15%	0%	15%	0%
Contract University/College	75%	4%	75%	1%
University/College	75%	4%	75%	1%
Restaurant/Food Service	85%	0%	85%	0%
Warehouse	10%	0%	10%	0%
Contract Apartment	40%	0%	n/a	n/a
High-rise Apartment	40%	0%	25%	0%
Mid-rise Apartment	40%	0%	25%	0%

2.5.5 Other Gas Uses

Natural gas use is used primarily for space heating, hot water heating, cooking and, to a lesser extent, space cooling. Other natural gas uses commonly found in commercial buildings include the following:

- Dehumidification
- Air reheat
- Steam distribution losses
- Sterilizers and other process loads
- Laboratory equipment
- Laundry equipment
- Fireplaces and patio heaters
- Pools and hot tubs.

Exhibit 2.10 presents the estimated EUIs for “other” gas uses, and their approximate percentages of total natural gas use for each sub sector and service region.

Exhibit 2.10: "Other" Natural Gas Use EUIs and % of Total Building Use

Sub Sector	Southern service region		Northern service region	
	Other EUI (MJ/m^2.yr.)	% of Total Natural Gas Use	Other EUI (MJ/m^2.yr.)	% of Total Natural Gas Use
Large Office	75	11%	70	9%
Small Office	40	6%	40	5%
Retail	20	3%	20	3%
Large Hotel	50	7%	50	6%
Small Hotel/Motel	60	8%	60	6%
Contract Hospital	250	12%	250	10%
Hospital	100	6%	100	5%
Nursing Home	70	7%	70	6%
School	5	1%	5	1%
Contract University/College	70	9%	70	8%
University/College	40	6%	40	5%
Restaurant/Food Service	10	0.4%	10	0.4%
Warehouse	20	4%	20	3%
Contract Apartment	20	3%	n/a	n/a
High-rise Apartment	20	3%	20	2%
Mid-rise Apartment	10	1%	10	1%

2.6 FLOOR SPACE ESTIMATES

The estimated floor area for each building sub sector was estimated by dividing the Union sales data by the whole building natural gas (energy) use intensity (EUI) that was generated by the CEEAM model using the input assumptions, as summarized in the preceding discussions. The general equation is shown below.

$$Floor\ area = \frac{Consumption}{(EUI_{heat})(FS_{heat}) + (EUI_{water\ htg})(FS_{water\ htg}) + (EUI_{cook})(FS_{cook}) + (EUI_{cool})(FS_{cool})(SAT_{cool}) + (EUI_{other})}$$

Where;

EUI is energy use intensity in MJ/m^2.yr.
FS is percent natural gas fuel share for the end use
SAT is percentage saturation for the end use

Exhibit 2.11: Base Year (2007) Estimated Floor Area by Sub Sector and Service Region (m^2)

Sub Sector	Southern service region	Northern service region	Total
Large Office	2,886,107	3,177,068	6,063,175
Small Office	4,933,040	6,783,010	11,716,050
Retail	9,112,392	800,307	9,912,699
Large Hotel	548,857	141,428	690,284
Small Hotel/Motel	284,703	83,181	367,883
Contract Hospital	951,177	105,241	1,056,418
Hospital	241,821	267,821	509,641
Nursing Home	1,512,124	656,390	2,168,514
School	4,291,254	2,019,322	6,310,576
Contract University/College	3,490,673	359,396	3,850,069
University/College	665,633	128,479	794,112
Restaurant/Food Service	1,096,109	130,800	1,226,909
Warehouse	4,965,853	208,694	5,174,547
Contract Apartment	336,230	0	336,230
High-rise Apartment	7,202,562	647,423	7,849,985
Mid-rise Apartment	3,804,397	741,767	4,546,164

2.7 SUMMARY OF BASE YEAR ENERGY USE

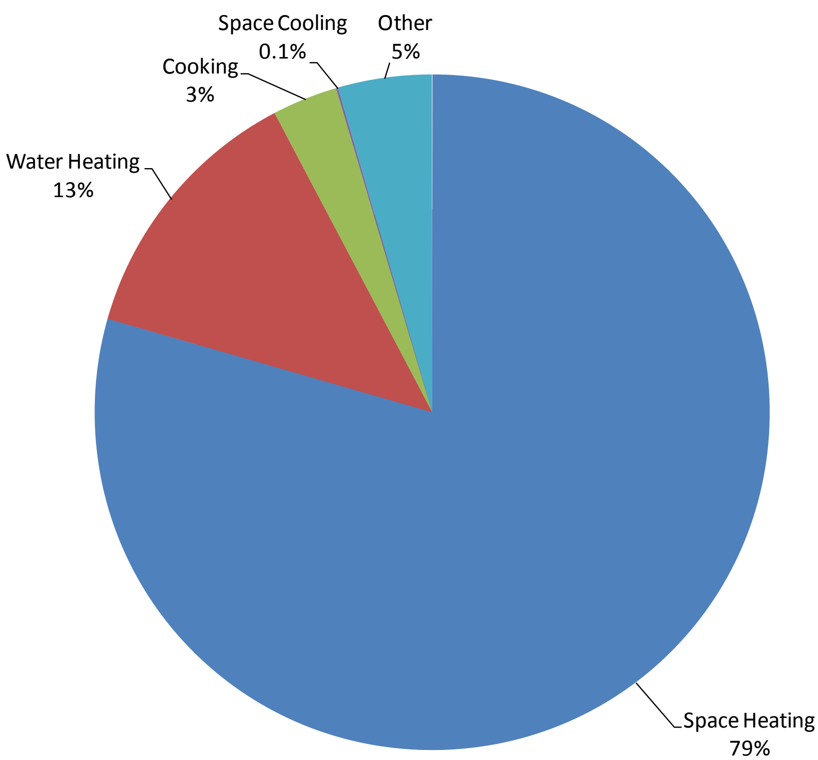
The summary of Base Year model results are presented in three separate Exhibits:

- Exhibit 2.12 presents the modelled results, broken out by sub sector and end use for the total Union Service Area. Note that the CSEEM model has been calibrated using the actual Union sales data in each service region. As a consequence, modelled results match the sales data exactly for each sub sector and service region.

- Exhibits 2.13 and 2.14 present the modelled results, broken out by sub sector and end use for the Southern and Northern service regions, respectively.

Exhibit 2.12: Base Year Results by Sub Sector and End Use – Total Service Region (1000 m^3/yr.)[16]

Sub Sector	Space Heating	Water Heating	Cooking	Space Cooling	Other	Total
Large Office	99,744	7,774	324	185	11,716	119,743
Small Office	213,790	15,367	626	0	12,519	242,302
Retail	147,344	9,583	4,219	0	5,274	166,419
Large Hotel	7,649	4,766	643	0	919	13,978
Small Hotel/Motel	4,849	2,718	59	0	588	8,214
Contract Hospital	41,177	10,879	1,096	291	7,026	60,469
Hospital	18,650	3,762	489	70	1,361	24,332
Nursing Home	42,669	12,719	2,843	0	4,045	62,276
School	127,355	7,415	1,783	0	841	137,394
Contract University/College	58,582	10,173	2,868	617	7,170	79,409
University/College	12,355	1,837	444	118	846	15,600
Restaurant/Food Service	39,992	15,664	25,853	0	326	81,836
Warehouse	61,965	3,307	138	0	2,752	68,162
Contract Apartment	5,038	1,854	22	0	179	7,093
High-rise Apartment	120,369	40,913	522	0	4,176	165,980
Mid-rise Apartment	74,936	24,848	484	0	1,210	101,478
Other Buildings						391,810
Other Contract Institutional Buildings						320,568
Total	1,076,463	173,581	42,413	1,280	60,948	2,067,064



[16] The pie charts in Exhibits 2.12, 2.13 and 2.14 present percentage of gas consumption by end use for modelled buildings only; the sub sectors Other Buildings and Other Contract Institutional Buildings are included in the total load, but not included in the respective pie charts.

Exhibit 2.13: Base Year Results by Sub Sector and End Use - Southern Service Region ($1000\ m^3$/yr.)

Sub Sector	Space Heating	Water Heating	Cooking	Space Cooling	Other	Total
Large Office	42,035	3,684	153	185	5,754	51,811
Small Office	78,448	6,438	262	0	5,245	90,394
Retail	132,804	8,803	3,876	0	4,844	150,327
Large Hotel	5,711	3,783	511	0	729	10,734
Small Hotel/Motel	3,255	2,100	45	0	454	5,854
Contract Hospital	36,081	9,787	986	286	6,321	53,461
Hospital	7,601	1,777	209	60	643	10,290
Nursing Home	27,505	8,846	1,978	0	2,814	41,142
School	80,437	5,028	1,209	0	570	87,245
Contract University/College	51,623	9,216	2,598	605	6,495	70,537
University/College	9,867	1,538	372	114	708	12,599
Restaurant/Food Service	34,490	13,981	23,076	0	291	71,838
Warehouse	58,355	3,173	132	0	2,640	64,300
Contract Apartment	5,038	1,854	22	0	179	7,093
High-rise Apartment	107,917	37,512	479	0	3,829	149,737
Mid-rise Apartment	60,288	20,765	405	0	1,011	82,468
Other Buildings						340,457
Other Contract Institutional Buildings						295,028
Total	741,454	138,286	36,312	1,251	42,528	1,595,315

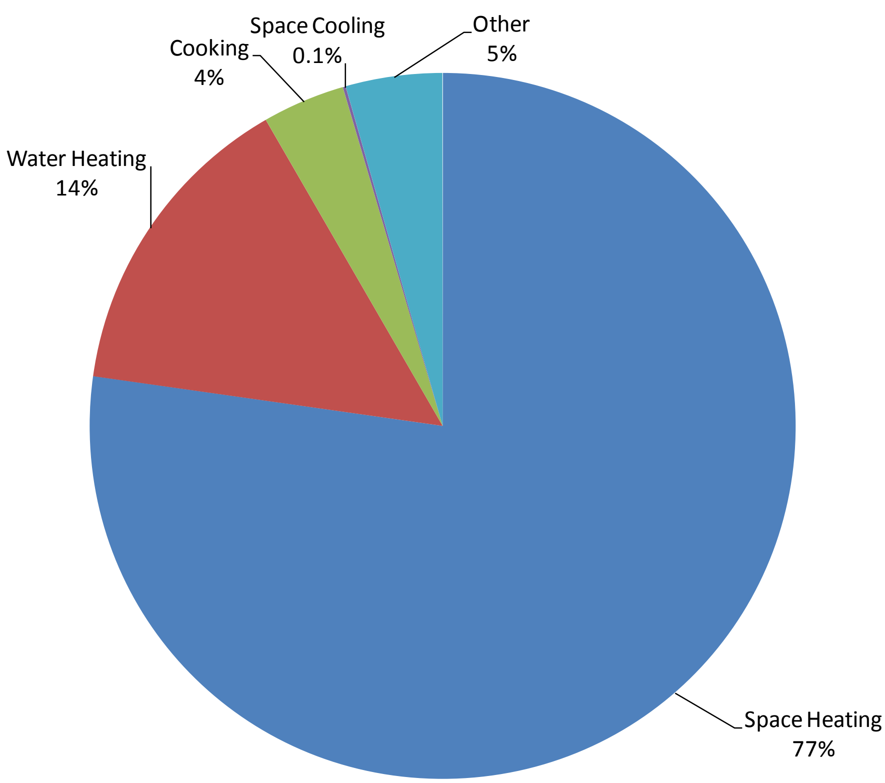
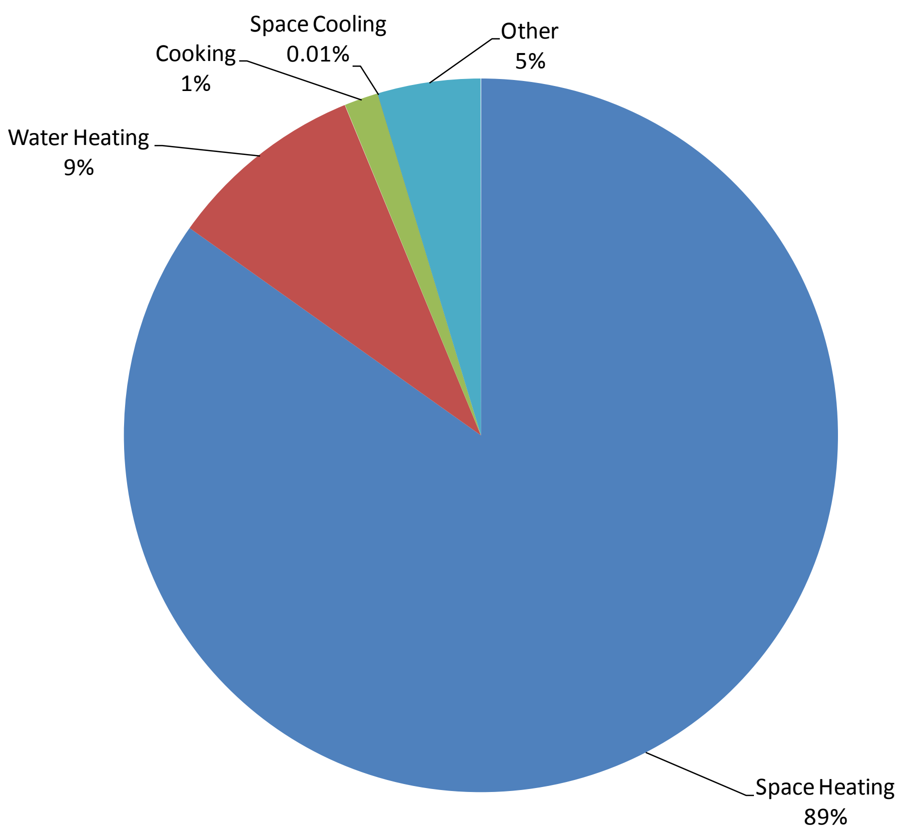


Exhibit 2.14: Base Year Results by Sub Sector and End Use - Northern Service Region ($1000\ m^3$/yr.)

Sub Sector	Space Heating	Water Heating	Cooking	Space Cooling	Other	Total
Large Office	57,708	4,090	170	0	5,962	67,931
Small Office	135,342	8,929	364	0	7,274	151,908
Retail	14,540	780	343	0	429	16,092
Large Hotel	1,938	983	133	0	190	3,243
Small Hotel/Motel	1,594	619	13	0	134	2,360
Contract Hospital	5,096	1,092	110	4	705	7,008
Hospital	11,049	1,985	280	9	718	14,042
Nursing Home	15,164	3,873	866	0	1,232	21,134
School	46,918	2,386	574	0	271	50,149
Contract University/College	6,959	957	270	12	674	8,872
University/College	2,488	299	72	4	138	3,001
Restaurant/Food Service	5,503	1,683	2,777	0	35	9,998
Warehouse	3,610	134	6	0	112	3,862
High-rise Apartment	12,452	3,401	43	0	347	16,243
Mid-rise Apartment	14,648	4,083	80	0	199	19,010
Other Buildings						51,354
Other Contract Institutional Buildings						25,541
Total	335,009	35,295	6,101	30	18,420	471,749



2.7.1 Interpretation of Results

Highlights of the results shown in Exhibits 2.13 and 2.14 are as follows:

Sub Sector

In the Southern service region, the sub sectors Other Buildings and Other Contract Institutional Buildings have the largest share of total gas consumption at 21% and 18% respectively. Among modelled sub sectors, Retail buildings and High-rise Apartment buildings each make up 9% of total gas consumption, followed by Contract Hospital at 6%.

In the Northern service region, Small Office accounts for the largest share of total gas consumption at 32%, followed by Large Office at 14%, Other Buildings at 11% and Schools at 10%.

End Use

In the Southern service region, space heating accounts for the largest share of gas consumption at 77%, followed by water heating at 14% and other at 5%.

In the Northern service region, space heating also accounts for the largest share of gas consumption at 89%, followed by water heating at 9% and other at 5%.

3. REFERENCE CASE

3.1 INTRODUCTION

This section presents the Commercial sector Reference Case for the study period 2007 to 2017. The Reference Case estimates the expected level of natural gas consumption that would occur over the study period in the absence of new Union energy-efficiency initiatives. The Reference Case, therefore, provides the point of comparison for the subsequent calculation of energy savings opportunities associated with each of the subsequent scenarios that are assessed within this study.

The discussion is presented within the following subsections:

- Development of Detailed Profiles—New Buildings
- “Natural” Changes Affecting Natural Gas Consumption
- Expected Growth in Building Stock
- End-use Model Results.

3.2 DEVELOPMENT OF DETAILED PROFILES—NEW BUILDINGS

For the purposes of this study, any buildings built subsequent to the base year (2007) were considered “new buildings.” The first task in building the Reference Case involved the development of detailed technical profiles that defined building envelope characteristics, HVAC, hot water, cooking equipment and electrical loads for the new buildings in each of the Commercial sub sectors. In each case, new building profiles were developed using CEEAM and the same approach described previously in the Base Year discussion.

A sample building profile summary for new Large Offices in the Southern service region is presented in Exhibit 3.1. It summarizes the major technical assumptions that have been used for new Large Offices in the development of the Reference Case. A complete set of detailed profiles for new buildings are presented in Appendix C (Southern service region) and D (Northern service region).

Exhibit 3.1: Sample New Building Profile Summary – New Large Office, Southern Service Region

Exhibit 3.2 highlights the resulting whole-building natural gas EUIs (as modeled in CEEAM) for each new commercial building segment. For reference purposes, it also shows whole-building EUIs for each of the existing building segments. In general, EUIs are lower for new buildings than for existing buildings.

General factors that lead to lower EUIs for new buildings as compared to existing buildings include the following:

- Improved thermal characteristics of building envelope systems including walls, roofs and windows
- Higher-efficiency heating systems, including improved controls and scheduling in some cases
- Higher-efficiency hot water heating systems and, in some cases, more efficient fixtures such as aerators and low-flow showerheads.

In general the following factors tend to lead to higher building EUIs in new buildings:

- Higher ventilation rates leading to an increase in space heating energy, especially in institutional buildings such as hospitals and nursing homes
- Higher gas shares for space heating and water heating in new buildings
- Lower internal heat gains due to improved lighting efficiencies.

In one case, University/College, the new building natural gas EUI is slightly larger than the corresponding existing building EUI. Reasons for this increase are noted below in Exhibit 3.2.

It should be noted that the Ontario Building Code (2006) is slated to require all new commercial and large residential construction to exceed the standards of the Model National Energy Code for Buildings by 25% starting in the year 2012. This change has been taken into account when constructing models for new buildings but has not been explicitly included. There remains considerable debate around this regulation among commercial builders, leaving implementation and enforcement uncertain. A brief discussion of the Ontario Building Code and other regulatory issues is included in section 3.3.7.

Exhibit 3.2: Comparison of Whole Building Gas EUIs – Southern Service Region (GJ/m²/yr.)

Sub Sector	Existing Buildings	New Buildings	Comments
Large Office	585	475	New office buildings have higher efficiency HVAC and envelope systems, and signifigantly lower internal heat gains due to improved lighting efficiency. Overall, this results in a lower whole building gas EUI.
Small Office	643	631	New office buildings have higher efficiency HVAC and envelope systems, and signifigantly lower internal heat gains due to improved lighting efficiency. Overall, this results in a lower whole building gas EUI.
Retail	618	532	New retail buildings are typically "big box" stores, with higher efficiency HVAC and envelope systems. Overall, this results in a lower whole building gas EUI.
Large Hotel	743	697	New hotels are generally equipped with higher efficiency HVAC systems and envelopes. Overall, this results in a lower whole building gas EUI.
Small Hotel/Motel	763	667	New hotels generally are equipped with higher efficiency HVAC systems and envelopes. Overall, this results in a lower whole building gas EUI.
Contract Hospital	2,125	1,513	New hospital buildings are equipped with higher efficiency HVAC systems and envelopes. This is generally offset by higher ventilation rates compared to existing hostpitals. Overall, this results in a lower whole building gas EUI.
Hospital	1,618	1,516	
Nursing Home	1,034	1,001	New nursing homes are equipped with higher efficiency HVAC systems and envelopes. This is offset by higher ventilation rates, and increased space heating gas share compared to existing nursing homes. Overall, this results in a slightly lower gas EUI.
School	751	669	New schools are generally equipped with higher efficiency HVAC systems and envelopes. This is partially offset by higher space heating and water heating EUIs. Overall, this results in a lower whole building gas EUI.
Contract University/College	770	735	New university/college buildings have more efficient HVAC and envelope systems, but generally have higher ventilation rates and a higher gas fuel share for space heating, this may result in a higher whole building EUI.
University/College	730	735	
Restaurant/Food Service	2,474	2,342	New restaurant/food service buildings have more efficient HVAC systems and envelopes. This is offset by higher ventilation rates, and slightly increased space heating and water heating gas shares, resulting in a slightly lower gas EUI.
Warehouse	754	488	New warehouse buildings have higher efficiency HVAC and envelope systems, resulting in a lower whole building EUI.
Contract Apartment	799	713	New highrise apartment buildings have higher efficiency HVAC and envelope systems and slightly higher gas fuel shares for water heating, resulting in a lower whole building EUI.
High-rise Apartment	782	719	
Mid-rise Apartment	757	687	New midrise apartment buildings have higher efficiency HVAC and envelope systems and slightly higher gas fuel shares for water heating, resulting in a lower whole building EUI.

3.3 "NATURAL" CHANGES AFFECTING NATURAL GAS CONSUMPTION

The next task involved an estimation of expected "natural" changes[17] in natural gas consumption patterns over the study period. The following factors were considered:

- Improvements in equipment efficiency, including new energy performance standards
- Expected (naturally occurring) increased stock penetration of more efficient natural gas equipment
- Interactive effects on natural gas space heating resulting from changes in building electricity use.

A discussion of the expected "natural" changes follows. In each case, the discussion identifies the technical change, the major driver(s) and the assumed natural gas impact.

3.3.1 Space Heating

Natural gas boilers being installed in new buildings are assumed to be a mix of standard (75% seasonal efficiency), near condensing (80% seasonal efficiency) and condensing boilers (90% seasonal efficiency). A weighted seasonal boiler efficiency[18] for existing and new buildings, showing a general trend toward higher boiler efficiencies, is presented in Exhibit 3.3.[19]

[17] "Natural changes" refer to those changes that are expected in the absence of any post-2008 Union programming.

[18] Estimated seasonal efficiencies are based on the estimated floor space weighted mix of boiler technologies/vintages/and operating characteristics for both existing and new buildings. CEEAM uses building heating loads and estimated average seasonal efficiencies to calculate gas consumption.

[19] Based on Marbek database, previous studies in similar jurisdictions and discussion with Union personnel.

Exhibit 3.3: Natural Gas Space Heating: Estimated Seasonal Boiler Efficiency in Existing and New Buildings – Southern Service Region (%)

Sub Sector	Weighted Seasonal Boiler Efficeincy	
	Existing Buildings	New Buildings
Large Office	78%	80%
Small Office	77%	79%
Retail	78%	80%
Large Hotel	77%	79%
Small Hotel/Motel	76%	80%
Contract Hospital	80%	82%
Hospital	80%	82%
Nursing Home	78%	80%
School	81%	83%
Contract University/College	80%	81%
University/College	80%	81%
Restaurant/Food Service	77%	80%
Warehouse	79%	81%
Contract Apartment	77%	80%
High-rise Apartment	77%	80%
Mid-rise Apartment	78%	79%

Similar efficiency improvement trends are also assumed for other space heating equipment including rooftop units, unit heaters and furnaces.

As discussed in Exhibit 3.2, space heating EUIs in new buildings are also driven lower by improved building envelope characteristics. At the same time, however, space heating EUIs are being driven higher by increased ventilation rates (mitigated to some degree by increasing levels of air-to-air heat recovery) and reduced internal waste heat gains due improved electrical equipment efficiency (e.g., lighting).

In the case of existing buildings, similar factors to those discussed above are expected to affect space heating loads over the course of the study period. These changes will take place at the time of natural equipment turnover (i.e., for boilers or rooftop units) or when existing buildings are renovated (i.e., improvements to building envelopes). Internal heating gains are also expected to decrease due to efficient lighting retrofits. The net effect of these natural changes is assumed to be an improvement in existing building space heating EUIs of 3% over the study period.

3.3.2 Domestic Hot Water

Gas water heating equipment is assumed to be distributed in new buildings as shown in Exhibit 3.4.

Exhibit 3.4: Distribution of Gas DHW Equipment in New Buildings, by Type for the Southern Service Region (% of Floor Space)

Sub Sector	Boiler	Tank-type
Large Office	14%	86%
Small Office	5%	95%
Retail	3%	97%
Large Hotel	71%	29%
Small Hotel/Motel	47%	53%
Contract Hospital	88%	12%
Hospital	88%	12%
Nursing Home	76%	24%
School	16%	84%
Contract University/College	88%	12%
University/College	88%	12%
Restaurant/Food Service	12%	88%
Warehouse	9%	91%
Contract Apartment	34%	66%
High-rise Apartment	34%	66%
Mid-rise Apartment	28%	72%

In existing buildings, improvements in water heating equipment and a higher market penetration of condensing technologies at time of stock turnover is expected to lead to a 3% improvement in existing building water heating EUIs over the study period.

3.3.3 Commercial Cooking

Commercial cooking EUIs for new buildings were assumed to be equivalent to those in existing buildings. Although high-efficiency commercial cooking equipment is available in the marketplace, there are no federal or provincial energy-efficiency regulations for such equipment in place in Canada.[20] In the absence of such regulations or available research on temporal trends in cooking EUIs, and the inclination of restaurant and food service decision makers to rank energy performance low on the list of factors considered when purchasing equipment, commercial cooking EUIs are assumed to stay constant for the purposes of this study.

[20] ENERGY STAR® does prescribe voluntary efficiency standards for some equipment, including gas-fired fryers and steam cookers. See www.oee.nrcan.gc.ca/energystar.

3.3.4 Space Cooling

For space cooling, overall EUIs, and gas cooling technologies are assumed to be the same for new buildings as for existing buildings. Natural gas share is assumed to be lower for new buildings. The small size of the gas cooling market means that a mix of gas cooling technologies and gas share for space cooling in new buildings will be in large part dependent on individual builders and contractors.

3.3.5 Other

Because of the relatively small size of the "miscellaneous" end use, most components included were assumed to be the same in new buildings as in old buildings. In some cases, miscellaneous EUIs are lower in new buildings due to lower levels of air reheat in new building design.

3.3.6 Interactive Effects from Changes to Electrical End Uses

"Natural" changes also occur in the electrical end uses and are incorporated in the CEEAM sub sector models. The two most relevant electrical end uses for this study are:

- Lighting
- Plug loads.

Lighting

The continued replacement of T12 fluorescent lighting and electromagnetic ballasts with T8 fluorescent lamps and electronic ballasts in existing buildings is occurring because of decreasing prices, increasing public recognition of the savings and changing energy performance codes and standards. Similarly, the federal and provincial governments have announced a commitment to phase out incandescent lighting from the marketplace, beginning in 2012. Both of these lighting changes will result in reduced lighting loads and, hence, reduced internal heat gains. As lighting loads decrease, winter heating loads will tend to increase.

Plug Loads

The density and variety of office and other plug load equipment is increasing. However, the electricity use of many types of office equipment has been decreasing due to programs such as ENERGY STAR®. Previous studies performed on behalf of the electrical utilities BC Hydro and Newfoundland Power/Newfoundland and Labrador Hydro, have assumed a low to intermediate growth scenario in terms of overall plug load. An increase in plug loads will tend to decrease heating loads via increased internal heat gains.

The net impacts of these electrical trends are included in the results provided in Section 3.3.8.

3.3.7 Additional Considerations

As noted in section 3.2, the Ontario Building Code is slated to require institutional, commercial and large residential buildings to achieve an energy performance 25% better than the Model National Energy Code for Buildings (MNECB). This requirement has not been explicitly considered in the new building profiles used to construct this reference case, although the CEEAM models constructed for new buildings incorporate many of the characteristics that would be required to meet the standard of 25% below MNECB requirements.

Natural Resources Canada (NRCan) has proposed an amendment to Canada's energy-efficiency regulations that would require gas-fired unit heaters to have a minimum full load thermal efficiency of 80%.[21] This regulation will particularly affect space heating in the Warehouse sub sector.

No attempt has been made to explicitly incorporate the above considerations into this Reference Case, as the outcome of the proposal discussion is currently uncertain. However, these considerations will be addressed as part of the Achievable Potential presented in later sections of this report.

3.3.8 Net Impact on Natural Gas Use

A comparison of new and existing building natural gas EUIs for the two largest energy-consuming end uses, space heating and water heating, is provided in Exhibit 3.5. The EUIs shown in Exhibit 3.5 combine the affects of changes to fuel share and technology penetrations.

As illustrated in Exhibit 3.5, the general trend in most sub sectors is towards lower space and water heating EUIs among new buildings. The exceptions shown are due to the impacts of increased ventilation rates and/or increased natural gas fuel shares.

[21] See www.oee.nrcan.gc.ca/regulations/bulletin/gas-unit-heaters-aprilr007.cfm for details of the NRCan proposal. Unit heater standards contained in this proposal were originally scheduled to come into effect August 8, 2008 and, as of November 2008, were expected to come into force in the near future (personal communication, NRCan Office of Energy Efficiency Equipment Standards group).

Exhibit 3.5: Comparison of Space Heating and Water Heating Gas EUIs – Southern Service Region (MJ/m²/yr.)

Sub Sector	Space Heating		Water Heating	
	Existing Buildings	New Buildings	Existing Buildings	New Buildings
Large Office	458	382	48	50
Small Office	552	549	49	49
Retail	545	459	36	37
Large Hotel	399	350	259	262
Small Hotel/Motel	419	338	277	283
Contract Hospital	1438	1083	387	288
Hospital	1200	1086	276	288
Nursing Home	695	682	220	220
School	691	599	44	54
Contract University/College	566	599	99	84
University/College	576	600	87	84
Restaurant/Food Service	1192	1043	480	496
Warehouse	709	443	24	24
Contract Apartment	569	485	207	206
High-rise Apartment	564	491	196	206
Mid-rise Apartment	538	470	205	203

3.4 EXPECTED GROWTH IN BUILDING STOCK

The next step in developing the Reference Case involved the development and application of estimated levels of floor space growth in each building sub sector and service region over the study period. For the purposes of this study, growth rates were derived from data provided by Union's Load Forecasting Group[22]. Separate rates were derived for each combination of rate class and service region. Additionally, growth rates for the Office and Retail sub sectors were adjusted directionally upward on the advice of Union forecasting staff. Exhibit 3.6 summarizes the estimated annual growth rates.

[22] Floor space growth rates were derived using Union's most recent sales forecast. It is important to note that both future natural gas sales and building stock growth are heavily dependent on prevailing economic conditions.

Exhibit 3.6: Annual Building Stock Growth Rates by Building Segment and Service Region (%/Yr.)

Subsector	Southern service region		Northern service region	
	2007 to 2012	2012 to 2017	2007 to 2012	2012 to 2017
Large Office	1.3%	1.3%	2.0%	2.0%
Small Office	1.1%	1.1%	1.0%	1.0%
Retail	1.2%	1.2%	1.9%	1.9%
Large Hotel	0.5%	0.5%	0.8%	0.8%
Small Hotel/Motel	0.5%	0.5%	0.8%	0.8%
Contract Hospital	0.7%	0.7%	1.1%	1.1%
Hospital	0.5%	0.5%	0.8%	0.8%
Nursing Home	0.5%	0.5%	0.8%	0.8%
School	0.6%	0.6%	1.0%	1.0%
Contract University/College	0.5%	0.5%	0.7%	0.7%
University/College	0.4%	0.4%	0.7%	0.7%
Restaurant/Food Service	0.5%	0.5%	0.8%	0.8%
Warehouse	0.5%	0.5%	0.8%	0.8%
Contract Apartment	0.6%	0.6%	0.9%	0.9%
High-rise Apartment	0.6%	0.6%	0.9%	0.9%
Mid-rise Apartment	0.6%	0.6%	1.0%	1.0%

3.5 END-USE MODEL RESULTS

The Reference Case results are presented in three exhibits:

- Exhibit 3.7 presents the model results for the total Union Service Area, with the results broken out by sub sector, end use and milestone year.
- Exhibits 3.8 and 3.9 present the same results for the Southern and Northern service regions respectively.

Exhibit 3.7: Reference Case for Annual Natural Gas Consumption for Total Union Service Area (1000 m^3/yr.)

Sub Sector	Milestone Year	Total	Space Heating	Water Heating	Cooking	Space Cooling	Other
Large Office	2007	119,743	99,744	7,774	324	185	11,716
	2012	126,391	105,187	8,370	366	185	12,283
	2017	133,820	111,289	9,032	413	185	12,902
Small Office	2007	242,302	213,790	15,367	626	0	12,519
	2012	249,172	219,539	15,945	675	0	13,013
	2017	256,584	225,759	16,565	727	0	13,533
Retail	2007	166,419	147,344	9,583	4,219	0	5,274
	2012	172,286	152,113	10,066	4,492	0	5,615
	2017	178,704	157,351	10,590	4,784	0	5,979
Large Hotel	2007	13,978	7,649	4,766	643	0	919
	2012	14,157	7,711	4,837	663	0	947
	2017	14,349	7,779	4,912	683	0	975
Small Hotel/Motel	2007	8,214	4,849	2,718	59	0	588
	2012	8,309	4,892	2,758	60	0	599
	2017	8,411	4,938	2,800	62	0	611
Contract Hospital	2007	60,469	41,177	10,879	1,096	291	7,026
	2012	61,200	41,634	11,009	1,129	300	7,128
	2017	61,988	42,130	11,150	1,163	310	7,234
Hospital	2007	24,332	18,650	3,762	489	70	1,361
	2012	24,737	18,915	3,839	504	73	1,407
	2017	25,169	19,199	3,919	519	77	1,454
Nursing Home	2007	62,276	42,669	12,719	2,843	0	4,045
	2012	63,202	43,248	12,889	2,924	0	4,141
	2017	64,181	43,865	13,070	3,007	0	4,239
School	2007	137,394	127,355	7,415	1,783	0	841
	2012	139,543	129,176	7,645	1,850	0	872
	2017	141,863	131,150	7,889	1,919	0	905
Contract University/College	2007	79,409	58,582	10,173	2,868	617	7,170
	2012	80,358	59,339	10,235	2,921	617	7,246
	2017	81,358	60,139	10,302	2,976	617	7,324
University/College	2007	15,600	12,355	1,837	444	118	846
	2012	15,792	12,506	1,853	455	118	861
	2017	15,995	12,665	1,869	466	118	876
Restaurant/Food Service	2007	81,836	39,992	15,664	25,853	0	326
	2012	83,081	40,369	15,851	26,527	0	335
	2017	84,383	40,772	16,049	27,218	0	344
Warehouse	2007	68,162	61,965	3,307	138	0	2,752
	2012	68,831	62,517	3,346	141	0	2,827
	2017	69,546	63,111	3,387	145	0	2,903
Contract Apartment	2007	7,093	5,038	1,854	22	0	179
	2012	7,156	5,068	1,881	23	0	184
	2017	7,223	5,101	1,910	24	0	190
High-rise Apartment	2007	165,980	120,369	40,913	522	0	4,176
	2012	167,681	121,218	41,620	538	0	4,305
	2017	169,513	122,153	42,369	555	0	4,437
Mid-rise Apartment	2007	101,478	74,936	24,848	484	0	1,210
	2012	102,600	75,548	25,301	500	0	1,251
	2017	103,815	76,222	25,782	517	0	1,293
Other Buildings	2007	391,810					
	2012	399,311					
	2017	407,437					
Other Contract Institutional Buildings	2007	320,568					
	2012	326,411					
	2017	332,733					
Total	2007	2,067,064	1,076,463	173,581	42,413	1,280	60,948
	2012	2,110,220	1,098,979	177,443	43,769	1,293	63,013
	2017	2,157,072	1,123,622	181,594	45,178	1,307	65,200

Exhibit 3.8: Reference Case for Annual Natural Gas Consumption for Southern Service Region (1000 m^3/yr.)

Sub Sector	Milestone Year	Total	Space Heating	Water Heating	Cooking	Space Cooling	Other
Large Office	2007	51,811	42,035	3,684	153	185	5,754
	2012	53,552	43,351	3,888	169	185	5,960
	2017	55,456	44,797	4,109	185	185	6,180
Small Office	2007	90,394	78,448	6,438	262	0	5,245
	2012	93,354	80,892	6,709	285	0	5,469
	2017	96,556	83,541	7,000	308	0	5,706
Retail	2007	150,327	132,804	8,803	3,876	0	4,844
	2012	155,243	136,761	9,223	4,115	0	5,144
	2017	160,595	141,086	9,676	4,370	0	5,463
Large Hotel	2007	10,734	5,711	3,783	511	0	729
	2012	10,843	5,741	3,829	524	0	749
	2017	10,959	5,774	3,878	538	0	769
Small Hotel/Motel	2007	5,854	3,255	2,100	45	0	454
	2012	5,911	3,280	2,123	47	0	462
	2017	5,971	3,307	2,147	48	0	470
Contract Hospital	2007	53,461	36,081	9,787	986	286	6,321
	2012	54,025	36,419	9,889	1,014	295	6,407
	2017	54,632	36,787	10,000	1,043	303	6,497
Hospital	2007	10,290	7,601	1,777	209	60	643
	2012	10,390	7,656	1,799	214	62	659
	2017	10,497	7,716	1,821	220	64	677
Nursing Home	2007	41,142	27,505	8,846	1,978	0	2,814
	2012	41,560	27,746	8,927	2,025	0	2,862
	2017	42,001	28,002	9,013	2,074	0	2,912
School	2007	87,245	80,437	5,028	1,209	0	570
	2012	88,005	81,022	5,148	1,247	0	588
	2017	88,831	81,663	5,274	1,287	0	607
Contract University/College	2007	70,537	51,623	9,216	2,598	605	6,495
	2012	71,276	52,205	9,262	2,644	605	6,561
	2017	72,054	52,818	9,312	2,691	605	6,628
University/College	2007	12,599	9,867	1,538	372	114	708
	2012	12,723	9,962	1,548	380	114	719
	2017	12,853	10,061	1,558	388	114	731
Restaurant/Food Service	2007	71,838	34,490	13,981	23,076	0	291
	2012	72,793	34,727	14,126	23,642	0	299
	2017	73,790	34,982	14,280	24,222	0	306
Warehouse	2007	64,300	58,355	3,173	132	0	2,640
	2012	64,883	58,829	3,208	135	0	2,710
	2017	65,506	59,339	3,246	139	0	2,782
Contract Apartment	2007	7,093	5,038	1,854	22	0	179
	2012	7,156	5,068	1,881	23	0	184
	2017	7,223	5,101	1,910	24	0	190
High-rise Apartment	2007	149,737	107,917	37,512	479	0	3,829
	2012	151,062	108,522	38,105	493	0	3,942
	2017	152,489	109,193	38,732	507	0	4,057
Mid-rise Apartment	2007	82,468	60,288	20,765	405	0	1,011
	2012	83,184	60,641	21,083	417	0	1,042
	2017	83,958	61,033	21,421	430	0	1,074
Other Buildings	2007	340,457					
	2012	346,178					
	2017	352,354					
Other Contract Institutional Buildings	2007	295,028					
	2012	299,986					
	2017	305,337					
Total	2007	1,595,315	741,454	138,286	36,312	1,251	42,528
	2012	1,622,124	752,820	140,747	37,375	1,261	43,758
	2017	1,651,062	765,201	143,377	38,474	1,271	45,048

Exhibit 3.9: Reference Case for Annual Natural Gas Consumption for Northern Service Region (1000 m^3/yr.)

Sub Sector	Milestone Year	Total	Space Heating	Water Heating	Cooking	Space Cooling	Other
Large Office	2007	67,931	57,708	4,090	170	0	5,962
	2012	72,839	61,836	4,482	197	0	6,323
	2017	78,365	66,492	4,923	227	0	6,722
Small Office	2007	151,908	135,342	8,929	364	0	7,274
	2012	155,818	138,648	9,236	391	0	7,544
	2017	160,028	142,217	9,565	419	0	7,827
Retail	2007	16,092	14,540	780	343	0	429
	2012	17,043	15,352	843	377	0	471
	2017	18,109	16,265	913	414	0	517
Large Hotel	2007	3,243	1,938	983	133	0	190
	2012	3,314	1,970	1,008	138	0	198
	2017	3,389	2,005	1,034	144	0	206
Small Hotel/Motel	2007	2,360	1,594	619	13	0	134
	2012	2,398	1,612	635	14	0	137
	2017	2,439	1,632	652	14	0	141
Contract Hospital	2007	7,008	5,096	1,092	110	4	705
	2012	7,175	5,214	1,120	115	5	721
	2017	7,356	5,343	1,150	120	7	737
Hospital	2007	14,042	11,049	1,985	280	9	718
	2012	14,347	11,258	2,040	290	11	747
	2017	14,672	11,483	2,098	299	14	778
Nursing Home	2007	21,134	15,164	3,873	866	0	1,232
	2012	21,642	15,502	3,962	899	0	1,279
	2017	22,180	15,862	4,057	933	0	1,327
School	2007	50,149	46,918	2,386	574	0	271
	2012	51,538	48,154	2,497	602	0	284
	2017	53,032	49,487	2,615	632	0	298
Contract University/College	2007	8,872	6,959	957	270	12	674
	2012	9,082	7,135	973	277	12	685
	2017	9,304	7,321	990	285	12	696
University/College	2007	3,001	2,488	299	72	4	138
	2012	3,070	2,544	305	75	4	141
	2017	3,142	2,604	311	77	4	145
Restaurant/Food Service	2007	9,998	5,503	1,683	2,777	0	35
	2012	10,288	5,642	1,725	2,885	0	36
	2017	10,593	5,790	1,769	2,996	0	38
Warehouse	2007	3,862	3,610	134	6	0	112
	2012	3,948	3,688	138	6	0	117
	2017	4,041	3,771	142	6	0	121
High-rise Apartment	2007	16,243	12,452	3,401	43	0	347
	2012	16,620	12,696	3,515	45	0	363
	2017	17,024	12,960	3,637	48	0	380
Mid-rise Apartment	2007	19,010	14,648	4,083	80	0	199
	2012	19,417	14,907	4,217	83	0	209
	2017	19,857	15,189	4,361	87	0	219
Other Buildings	2007	51,354					
	2012	53,133					
	2017	55,083					
Other Contract Institutional Buildings	2007	25,541					
	2012	26,426					
	2017	27,396					
Total	2007	471,749	335,009	35,295	6,101	30	18,420
	2012	488,096	346,159	36,696	6,394	33	19,255
	2017	506,009	358,422	38,217	6,704	36	20,153

3.5.1 Comparison with Union Load Forecast

The Reference Case presented in Exhibits 3.7 through 3.9 is closely aligned with the Union commercial forecast for both total sales volume as well as sales volume by service region. Union has provided a consumption forecast for the years 2008-2012. This reference case has been calibrated to Union's forecast sales growth rates (in the absence of DSM programming) to 2012. A constant growth rate to 2017 is assumed.

For the Total Union Service Area, the 2008-2012 Union volume forecast shows an overall sales increase of approximately 1.7%. Pro-rating this growth over a five-year period gives an increase of 2.1%. The Reference Case shown in Exhibit 3.7 gives a 2.1% increase from 2007-2012 and a further 2.2% increase from 2012-2017.

In the Southern service region, the pro-rated five-year Union volume forecast shows an overall sales increase of 1.8%. The Reference Case shown in Exhibit 3.8 gives a 1.7% increase from 2007-2012 and a further 1.8% increase from 2012-2017.

In the Northern service region, the pro-rated five-year Union volume forecast (2008-2012) shows an overall sales increase of 3.6%. The Reference Case shown in Exhibit 3.9 gives a 3.5% increase from 2007-2012 and a further 3.7% increase from 2012-2017.

4. ENERGY-EFFICIENCY MEASURES

4.1 INTRODUCTION

This section identifies and assesses the financial and economic attractiveness of the selected energy-efficiency measures for the Commercial sector. The discussion is organized and presented as follows:

- Methodology
- Summary of energy-Efficiency Results
- Description of energy-Efficiency Technologies and Measures.

4.2 METHODOLOGY

The following steps were employed to assess the energy-efficiency measures:

- Select candidate energy-efficiency measures
- Establish technical performance for each option within a range of applicable load sizes and/or service region conditions (e.g., degree days or full load-equivalent hours)
- Establish the capital, installation and operating costs for each option
- Calculate the simple payback from the customer's perspective
- Calculate the measure total resource cost (TRC)
- Calculate the benefit/cost ratio.

A brief discussion of each step is outlined below.

Step 1 Select Candidate Measures

The candidate measures were selected in close collaboration with Union personnel based on a combination of a literature review and the previous experience of both the consultants and Union personnel. The selected measures are all considered to be technically proven and commercially available, even if only at an early stage of market entry. Technology costs, which will be addressed in this section, were not a factor in this initial selection of candidate technologies.

Step 2 Establish Technical Performance

Information on the performance improvements provided by each measure was compiled from available secondary sources, including the experience and on-going research work of study team members. As applicable, the energy impacts of the measures are reported for both natural gas and electricity. Where available, technical performance inputs have been drawn from data provided by Union Gas, specifically July 2008 DSM input assumptions.

Step 3 Establish Capital, Installation and Operating Costs for Each Measure

Information on the cost of implementing each measure was also compiled from secondary sources, including the experience and on-going research work of study team members. As applicable, both the incremental and full costs were estimated for each measure. Where available, cost inputs have been drawn from data provided by Union Gas, specifically July 2008 DSM input assumptions.

The incremental cost is applicable when a measure is installed in a new facility, or at the time of equipment turnover in an existing facility. In this case, incremental cost is defined as the difference between the energy-efficiency measure and the "baseline" technology. The full cost is applicable when an operating piece of equipment is replaced with a more efficient model prior to the end of its useful life.

In both cases, the costs and savings are annualized, based on the number of years of equipment life and the discount rate. The costs incorporate applicable changes in annual O&M costs and all costs are expressed in constant (2008) dollars.

Step 4 Calculate Simple Payback

The simple payback is generated to show the customer's financial perspective. Simple payback is "a measure of the length of time required for the cumulative savings from a project to recover its initial investment cost and other accrued costs, without taking into account the time value of money. The simple payback period is usually measured from the service date of the project."[23] The cost of the measure (incremental or full, as appropriate) is divided by the expected annual savings. The answer is given in years**.**

The following equation illustrates how this calculation is applied to a situation where an upgrade has a higher upfront cost than the baseline technology, but lower ongoing operating costs:

$$\text{Payback}_{\text{(years)}} = (\text{CostUpgr} - \text{CostBase})/(\text{AnnBase} - \text{AnnUpgr})$$

where:

CostUpgr	= initial capital cost of the upgrade measure ($)
CostBase	= initial capital cost of the baseline measure ($)
AnnUpgr	= ongoing operating cost of the upgrade ($/yr.)
AnnBase	= ongoing operating savings of the base ($/yr.)

Step 5 Calculate the Measure TRC

The measure TRC calculates the net present value of energy and water savings that result from an investment in an efficiency measure. The measure TRC is equal to its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy, water and equipment O&M costs. This calculation includes, among others, the following inputs: the avoided natural gas, electricity and water supply costs, the life of the technology and the selected discount rate, which in this analysis has been set at 10%.

[23] Sieglinde K. Fuller and Stephen R. Petersen. *Life Cycle Costing Manual for the Federal Energy Management Program.* National Institute of Standards and Technology Handbook 135, 1995 Edition, Washington, DC.

A technology or measure with a positive TRC value is included in subsequent phases of the analysis, which consists of the economic and Achievable Potential scenarios. A measure with a negative TRC value is not economically attractive and is therefore not included in subsequent stages of the analysis.

It should be noted that the measure TRC provides an initial screen of the technical options. Considerations such as program delivery costs, incentives, etc., are incorporated in later detailed program design stages, which are beyond the scope of this study.

Step 6 Calculate Benefit/Cost Ratio

The measure benefit/cost ratio indicates the relative attractiveness of the measures. A measure that has a benefit/cost ratio in excess of 1.0 means that the measure's benefits outweigh its costs; it is, therefore, included in subsequent stages of the analysis. Similarly, a measure with a benefit/cost ratio that is well in excess of one (e.g., 3.0) means that it is very attractive. A measure with a benefit/cost ratio of less than 1.0 means that its costs outweigh its benefits and, hence, is not included in subsequent stages of the analysis.

4.2.1 Energy Costs

The financial and economic results that are presented in this section are based on the following:

- Avoided supply cost of natural gas
- Avoided supply cost of electricity
- Customer energy prices.

A brief discussion of each is provided below.

Avoided Supply Cost of Natural Gas

Natural gas avoided supply costs were provided by Union. The data provided were segmented into base load and weather-sensitive rates and their resulting NPVs (net present values). The rates were forecast for a 30-year time span. The avoided supply costs also incorporate a GHG adder that accounts for carbon dioxide emissions resulting from natural gas consumption. A cost of $15/tonne CO_2e (per tonne of CO_2 equivalent) is employed until 2012 and the price is increased to $20 /tonne CO_2e starting in 2013. An emissions coefficient of 0.001903 tonnes CO_2e/m^3 (1903 g CO_2e/m^3) is used in this analysis.[24] The resulting avoided supply costs for natural gas are shown in Exhibit 4.1.

[24] Based on emission factors and Global Warming Potentials (GWPs) presented in Environment Canada, National Inventory Report (1990-2005): Greenhouse Gas Sources and Sinks in Canada, p. 23 and 583, April 2007.

Exhibit 4.1: Natural Gas – Avoided Supply Costs

Year	Base load		Weather Sensitive	
	Gas Rates ($/m^3)	NPV ($/m^3)	Gas Rates ($/m^3)	NPV ($/m^3)
1	0.39898	0.39898	0.40143	0.40143
2	0.38189	0.74614	0.38823	0.75436
3	0.36510	1.04787	0.36231	1.05378
4	0.37148	1.32698	0.36864	1.33075
5	0.37799	1.58515	0.37510	1.58694
6	0.39425	1.82995	0.39130	1.82991
7	0.40101	2.05631	0.39800	2.05457
8	0.40790	2.26562	0.40483	2.26231
9	0.41492	2.45919	0.41179	2.45442
10	0.42207	2.63818	0.41889	2.63207
11	0.42936	2.80372	0.42611	2.79635
12	0.43678	2.95681	0.43348	2.94828
13	0.44435	3.09839	0.44098	3.08879
14	0.45206	3.22934	0.44863	3.21874
15	0.45992	3.35045	0.45642	3.33893
16	0.46793	3.46247	0.46436	3.45010
17	0.47608	3.56608	0.47245	3.55292
18	0.48440	3.66191	0.48070	3.64802
19	0.49287	3.75056	0.48910	3.73599
20	0.50150	3.83256	0.49766	3.81736
21	0.51030	3.90841	0.50639	3.89263
22	0.51927	3.97858	0.51528	3.96226
23	0.52840	4.04349	0.52433	4.02668
24	0.53771	4.10354	0.53357	4.08626
25	0.54719	4.15910	0.54297	4.14139
26	0.55686	4.21049	0.55256	4.19239
27	0.56671	4.25804	0.56232	4.23957
28	0.57674	4.30204	0.57228	4.28322
29	0.58697	4.34274	0.58242	4.32361
30	0.59739	4.38040	0.59275	4.36098

Avoided Supply Cost of Electricity and Water

The avoided supply costs of electricity and water used in this analysis were also provided by Union and are shown in Exhibit 4.2. The electricity costs also include a GHG adder to account for average carbon dioxide emissions from electricity production in Ontario. A method similar to that described for the natural gas avoided costs was used. An emissions coefficient of 0.000220 tonnes CO_2e/kWh (220 g CO_2e/kWh) is used in this analysis.[25]

[25] Based on Ontario emission factors presented in Environment Canada, National Inventory Report (1990-2005): Greenhouse Gas Sources and Sinks in Canada, p. 521, April 2007.

As the same electricity avoided cost value was used for both service regions, no attempt was made to generate distinct service region values in this study.

Exhibit 4.2: Water and Electricity – Avoided Supply Costs

Year	Water Rates		Electricity Rates	
	Rates ($/1000 L)	NPV ($/1000 L)	Rates ($/kWh)	NPV ($/kWh)
1	1.68504	1.68504	0.08032	0.08032
2	1.71705	3.24599	0.08177	0.15465
3	1.74967	4.69200	0.08324	0.22345
4	1.78292	6.03154	0.08474	0.28712
5	1.81679	7.27243	0.08627	0.34604
6	1.85131	8.42195	0.08922	0.40144
7	1.88649	9.48682	0.09081	0.45271
8	1.92233	10.47328	0.09243	0.50014
9	1.95886	11.38710	0.09408	0.54403
10	1.99607	12.23363	0.09577	0.58464
11	2.03400	13.01783	0.09748	0.62223
12	2.07265	13.74428	0.09923	0.65701
13	2.11203	14.41723	0.10101	0.68919
14	2.15215	15.04064	0.10282	0.71897
15	2.19304	15.61813	0.10467	0.74654
16	2.23471	16.15311	0.10655	0.77204
17	2.27717	16.64869	0.10847	0.79565
18	2.32044	17.10777	0.11042	0.81750
19	2.36453	17.53305	0.11242	0.83772
20	2.40945	17.92702	0.11445	0.85643
21	2.45523	18.29197	0.11652	0.87375
22	2.50188	18.63005	0.11862	0.88978
23	2.54942	18.94324	0.12077	0.90461
24	2.59786	19.23336	0.12296	0.91835
25	2.64722	19.50212	0.12519	0.93106
26	2.69751	19.75109	0.12747	0.94282
27	2.74877	19.98173	0.12978	0.95371
28	2.80099	20.19538	0.13214	0.96379
29	2.85421	20.39330	0.13455	0.97312
30	2.90844	20.57665	0.13700	0.98176

1 kWh=3.6 MJ; 1 GJ=1000 MJ

Customer Resource Prices

The customer resource prices used in this analysis are presented in Exhibit 4.3. These values are used in the calculation of customer payback periods that are presented in later sections of this report. In the case of both electricity and natural gas, the prices shown are based on July 2008 rate schedules; in the case of electricity, prices incorporate both energy and demand charges.

Exhibit 4.3: Customer Resource Prices

	Nat. Gas[26] ($/m^3)	Electricity[27] ($/kWh)	Water[28] ($/1000L)
Northern service region	0.466	0.103	2.25
Southern service region	0.441	0.111	3.05

1kWh=3.6 MJ; 1 GJ=1000 MJ

4.3 SUMMARY OF ENERGY-EFFICIENCY SCREENING RESULTS

A summary of the screening results for the energy-efficiency options is presented in Exhibit 4.4. Due to the number of measures assessed, the following exhibits only show results for those options that pass the TRC screen. Analysis of all measures, including those options that did not pass the economic screen, is contained in Appendix E.

[26] Natural gas rates are approximate estimates based on Union rates (as of July 25, 2008) in each service region and average natural gas consumption levels in each service region.

[27] Customer electricity rates are based on electricity rates charged by EnWin (utility which services London) and North Bay Hydro (according to their websites, as of July 2008). Delivery charge is estimated based on monthly average peak demand of 250 kW.

[28] Water rates based on resource rates in London (South) and North Bay (North) and an approximate annual water consumption of 8,000 m^3.

Exhibit 4.4: Summary of Measure TRC Screening Results Commercial Sector Energy-efficiency Options – Average Operating Conditions

Measure Name	Target Market			Simple Payback (Yrs)	B/C Ratio
	Sub Sector(s)	Vintage	Full/ Incr		
High-Performance Glazings	All	E	I	5.7	1.73
Super High-Performance Glazings	All	E	I	16.9	0.58
Wall Insulation	All	E	I	30.6	0.28
Roof Insulation	All	E	I	7.6	1.14
Air Sealing	All	E	F	3.8	1.10
Air Curtains	All	E	F	1.2	6.33
Vinyl Strip Curtains	All	E	F	2.7	1.32
Fast Moving Doors	All	E	I	53.1	0.11
L-Shaped Vestibule	All	E	I	0.0	N/A
Turnstile Doors	All	E	I	14.9	0.63
Condensing Boiler - Baseline: Standard Boiler - 1,500 FLE hours	All	E	I	5.3	1.78
Condensing Boiler - Baseline: Near-condensing - 1,500 FLE hours	All	E	I	8.1	1.17
Near-Condensing Boiler - Baseline: Standard Boiler - 1,500 FLE hours	All	E	I	1.9	4.86
Condensing Unit heater - Baseline: Standard efficiency - 1,500 FLE hours	All	E	I	2.4	3.54
High Efficiency Rooftop Unit - Baseline: Standard efficiency - 1,500 FLE hours	All	E	I	2.2	3.89
Condensing Rooftop Unit - Baseline: Standard efficiency - 1,500 FLE hours	All	E	I	5.2	1.68
Gas Absorption Heat Pump - Baseline: standard efficiency boiler - 1,500 FLE hours	All	E	I	2.9	2.64
Steam Plant Efficiency Measures	All	E	F	1.2	4.97
HVLS De-stratification Fans	All	E	F	2.8	2.61
Heat Reflector Panels	All	E	F	3.5	2.40
Programmable Thermostats	All	E	F	2.4	3.13
Demand Controlled Ventilation	All	E	F	1.7	3.36
Demand Control Kitchen Ventilation	All	E	F	2.1	4.05
Heat Recovery	All	E	I	3.4	2.20
Furnace Boiler Tune Ups	All	E	F	1.7	0.98
Condensing Furnace	All	E	I	2.6	3.21
Infrared Heaters	All	E	I	2.0	4.38
Solar Preheated Make-up Air	All	E	F	12.3	0.70
Condensing Water Heater - baseline: standard efficiency - 1,000 FLE hours	All	E	I	4.1	2.26
Condensing Storage Water Heater - baseline: standard efficiency - 1,000 FLE hours	All	E	I	3.4	2.26
Tankless Water Heater - baseline: standard efficiency - 1,000 FLE hours	All	E	I	6.0	1.44
Drainwater Heat Recovery - 10 minute shower, 3 times per day	All	E	I	9.9	0.88
Low-Flow Faucet Aerators - 3 min/day	All	E	F	0.4	14.17
Low-Flow Showerheads - 10 min/day	All	E	F	0.2	20.04
Pre-Rinse Spray Valve - 40 min/day	All	E	F	0.2	13.79
Solar Weater Heating System - baseline: standard efficiency - 1,000 FLE hours	All	E	F	20.7	0.42
Booster Water Heater - 800 FLE hours	All	E	I	7.6	1.14
Commercial Cooking - High-Efficiency Griddle	All	E	I	5.4	1.11
Commercial Cooking - High-Efficiency Broiler	All	E	I	0.5	11.16
Commercial Cooking - High-Efficiency Oven	All	E	I	8.3	0.72
Commercial Cooking - High-Efficiency Fryer	All	E	I	4.0	1.51
Building Recommissioning	All	E	F	0.9	3.63
Advanced Building Automation Systems	All	E	F	3.4	1.58
High-Performance New Construction - 25% more efficient	All	N	I	4.7	1.85
High-Performance New Construction - 40% more efficient	All	N	I	4.8	1.80

4.4 DESCRIPTION OF ENERGY-EFFICIENCY TECHNOLOGIES AND MEASURES

This sub section provides a brief description of each of the energy-efficiency technologies and measures that are included in this study, as listed in Exhibit 4.5.

Exhibit 4.5: Energy-efficiency Technologies and Measures - Commercial Sector

Building Envelope:
- High-Performance Glazings
- Super High-Performance Glazings
- Wall Insulation Upgrade
- Roof Insulation Upgrade
- Air Sealing
- Air Curtains
- Vinyl Strip Curtains
- Fast-Moving Doors
- L-Shaped Vestibules
- Turnstile Doors

Heating, Ventilating and Air-Conditioning:
- Condensing Boilers
- Near-Condensing Boilers
- Condensing Unit Heaters
- High-Efficiency Rooftop Units
- Condensing Rooftop Units
- Absorption Heat Pumps
- Steam Plant Efficiency Measures
- HVLS De-stratification Fans
- Heat Reflector Panels
- Programmable Thermostats
- Heat Recovery
- Demand Controlled Ventilation
- Demand Control Kitchen Ventilation
- Furnace & Boiler Tune-ups
- Condensing Furnaces
- Infrared Heaters
- Solar Preheated Make-up Air

Domestic Hot Water:
- Condensing Water Heaters
- Condensing Tank-Type Water Heaters
- Tankless Water Heaters
- Drainwater Heat Recovery
- Low-Flow Faucet Aerators & Showerheads
- Low-Flow Pre-Rinse Spray Valves
- Solar Water Heating
- Booster Water Heaters

Cooking:
- Efficient Griddles
- Efficient Broilers
- Efficient Ovens
- ENERGY STAR® Fryers

Whole Building:
- Building Recommissioning
- Advanced Building Automation Systems
- High-Performance New Building Construction
    - Includes high-efficiency building envelopes, space heating and ventilation equipment, water heating equipment, food preparation equipment, whole building measures, LEED building criteria and specific technologies and practices such as multi-unit residential patio beam insulation, green roofs and cellular concrete.

The discussion is organized and presented in the following sub sections:

- Building envelope
- Heating, ventilating and air-conditioning
- Domestic hot water
- Cooking
- Whole building.

Each option is discussed below, with a brief description of the measure, savings relative to the baseline, typical installed costs, applicability and co-benefits. Where applicable, measures have been evaluated over a range of typical operating conditions. Detailed cost and performance data are provided in Appendix E.

4.4.1 Building Envelope

This study considered ten building envelope upgrade measures:

- High-Performance Glazings
- Super High-Performance Glazings
- Wall Insulation Upgrade
- Roof Insulation Upgrade
- Air Sealing
- Air Curtains
- Vinyl Strip Curtains
- Fast-Moving Doors
- L-Shaped Vestibules
- Turnstile Doors.

An overview of each upgrade measure is presented below.

High-Performance Glazings

High-performance glazings refer to a variety of technologies that can be used alone or in combination to provide an array of benefits, including lower energy costs, enhanced daylighting opportunities, reduced heating and cooling loads and more comfortable spaces. They incorporate one or more of the following:

- Double or triple glazing with a sealed insulating glass unit
- Low-E glass
- Inert gas such as argon or krypton in the sealed unit
- Low conductivity or "warm edge" spacer bars
- Insulated frames and sashes.

When combined these features will create windows with U-values of 0.32 Btu/hr.ft^2.^{o}F[29] or lower. In general, glazing upgrade opportunities are most attractive in sub sectors with high typical window/wall ratios, such as office buildings.

Measure Profile	
Applicable Building Types	All
Vintage	Existing and new
Costs	\$5/ft^2 (of glazing area) incremental cost
Savings	10% of space heating energy
Useful Life	30 years

[29] Maximum ENERGY STAR® qualifying U-value for windows in the Union service territory.

This measure involves upgrading to a glazing system with an overall U-value of 0.32 Btu/hr.ft^2.^{o}F. It is applicable to both existing buildings (at end of window life cycle) and new construction. The baseline is a standard double-glazed window with an overall U-value of 0.46 Btu/hr.ft^2.^{o}F. The incremental cost is $5 per square foot of window area,[30] the savings are 10%[31] of space heating energy and the service life is 30 years.[32]

Super High-Performance Glazings

Super high-performance glazing systems such as High Insulation Technology (HIT) windows consist of low-E coated films suspended inside an insulating glass unit. These units can be incorporated into both window and curtain wall systems. One example is the Visionwall window and curtain wall system manufactured by Visionwall Corporation,[33] which has thermal resistance R-values ranging from 3 to 7 hr.ft^2.^{o}F/Btu, low shading coefficients and high visible light transmission. In addition to superior insulating performance and lower energy costs, the co-benefits include enhanced comfort, noise reduction, elimination of perimeter heating and reduced HVAC equipment costs.

Measure Profile	
Applicable Building Types	All
Vintage	Existing and new
Costs	$12.50/ft^2 (of glazing area) incremental cost
Savings	15% of space heating energy
Useful Life	30 years

This measure involves upgrading glazing to a high-performance glazing system with an overall U-value of 0.2 Btu/hr.ft^2.^{o}F (R-5). It is applicable to both existing buildings (at end of window life cycle) and new construction. The baseline is an office building with standard double glazing with an overall U-value of 0.46 Btu/hr.ft^2.^{o}F (R-2.2). The incremental cost is $12.50[34] per square foot of glazing area, the savings are 15%[35] of space heating energy and the service life is 30 years.[36]

[30] ACEEE.

[31] CEEAM simulations.

[32] BC Hydro QA Standard.

[33] www.visionwall.com.

[34] Marbek database of technology costs.

[35] CEEAM simulation of office building.

[36] BC Hydro QA Standard.

Wall Insulation Upgrade

Measure Profile	
Applicable Building Types	All
Vintage	Existing and new
Costs	$1.38/ft^2 (floor area) incremental cost
Savings	9% of space heating energy
Useful Life	20 years

Various insulating materials and methods can be used to upgrade wall insulation, including applying rigid polystyrene board to the exterior of a building or installing fiberglass batts between interior wall studs. In addition to superior insulating performance and lower energy costs, the co-benefits include enhanced comfort, noise reduction and reduced HVAC equipment costs.

This measure involves upgrading wall insulation to R-24. It is applicable to both existing buildings (at time of renovations) and new construction. The baseline is a retail building with R-12 wall insulation. The incremental cost is $1.38[37] per square foot of floor area, the savings are 9%[38] of space heating energy and the service life is 20 years.[39]

Roof Insulation Upgrade

Measure Profile	
Applicable Building Types	All
Vintage	Existing and new
Costs	$1/ft^2 (roof area) incremental cost
Savings	20% of heating energy
Useful Life	20 years

Upgrading insulation on a built-up roofing system typically involves adding additional layers of rigid insulation at the time of re-roofing. In addition to superior insulating performance and lower energy costs, the co-benefits include enhanced comfort, noise reduction and reduced HVAC equipment costs.

This measure involves upgrading roof insulation to R-22. It is applicable to both existing buildings (at time of re-roofing) and new construction. The baseline is a retail building with R-12 roof insulation. The incremental cost is $1 per square foot of roof area,[40] the savings are up 20%[41] of heating energy (depending on building geometry) and the service life is 20 years.[42]

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[37] Marbek database.

[38] CEEAM simulation.

[39] BC Hydro QA Standard.

[40] Marbek database.

[41] CEEAM simulation.

[42] BC Hydro QA Standard.

Air Sealing

Air leakage control involves the identification and sealing of air leakage paths within the building envelope. Many of the leaks are obvious breaks in the air barrier system, such as through and around doors and windows and mechanical penetrations. Other air leaks are more difficult to identify including the wall/roof interface, plumbing stacks and elevator shafts that can channel air directly from the ground floor to the penthouse. Air sealing typically involves the systematic effort of applying insulating foam, caulking and weather stripping to improve the integrity of the building envelope system and control the stack effect. Suitable applications include other facilities with poorly maintained envelopes and high-rise buildings. Blocking air leaks brings many benefits, such as increased comfort, reduced heat loss, protection of the building structure and reduction of noise and dust from outdoors.

Measure Profile	
Applicable Building Types	All
Vintage	Existing and new
Costs	$\$0.10/ft^2$ full cost
Savings	5% of space heating energy
Useful Life	6 years

This measure involves controlling air leakage in a building, including applying insulating foam, caulking and weather –stripping, and performing "blower door" tests where appropriate. It is applicable to both existing buildings and new construction. The baseline is a high-rise office building with a poor envelope. The cost is $\$0.10/ft^2$ per square foot,[43] the savings are 5% of space heating energy[44] and the service life is six years.[45]

Air Curtains

Air curtain systems use a fan to generate a laminar airflow across an open doorway. This mass flow of air acts as a barrier, reducing outside air infiltration by approximately 90%, thus preventing unwanted heat transfer both at the building envelope and between rooms within the building. Typical applications include entrances to retail buildings, overhead garage doors, loading docks and refrigerated rooms. The co-benefits include protecting employees from adverse environmental conditions such as cold drafts and dust.

Measure Profile	
Applicable Building Types	Retail, Warehouse, Garage
Vintage	Existing & new
Costs	$2,500 per double door full cost
Savings	85% of heat loss through door
Useful Life	15 years

[43] Marbek database.

[44] CEEAM simulation.

[45] BC Hydro QA Standard.

This measure involves the installation of an air curtain to a double door entrance. It is applicable to both existing buildings and new construction. The baseline is a retail store with a double door entrance that is open for four hours per day. The cost is $2,500[46] per double door, the savings are 85%[47] of heat loss through the door and the service life is estimated to be 15 years.[48]

Vinyl Strip Curtains

Measure Profile	
Applicable Building Types	All
Vintage	Existing & new
Costs	Full cost of $420 per 8' x 8' door
Savings	60% of energy use associated with air infiltration through open doors
Useful Life	5 years

Vinyl strip doors act as a physical barrier to air infiltration, reducing outside air infiltration through the open doorway by an estimated 60%. This prevents unwanted heat transfer at the building envelope or between rooms within the building. Typical applications include loading docks and refrigerated rooms.

This measure involves the installation of a vinyl strip curtain on a standard sized (8' x 8') loading dock. It is applicable to both existing buildings and new construction. The baseline is a loading dock door with no additional treatment, which is open one hour per day. The full cost is $420 per door[49], the savings are 60% over the baseline[50] and the service life is estimated to be 5 years.[51]

High-Speed Doors

Measure Profile	
Applicable Building Types	All
Vintage	Existing & new
Costs	Incremental cost of $20,500 per 16' x16' door
Savings	87% of energy loss associated with air infiltration during door opening and closing
Useful Life	10 years

High-speed doors reduce unwanted heat transfer at the building envelope or between rooms within the building by minimizing the amount of time that doors are left open.

46 Enbridge Gas Distribution DSM input assumptions.

47 Marbek estimated for the effectiveness of Enershield MCS-72 air curtain.

48 Enbridge Gas Distribution DSM input assumptions.

49 Supplier information and RS Means.

50 Marbek estimate.

51 Marbek estimate.

Typical applications include overhead garage doors, and loading docks. Co-benefits include reduced likelihood of damage due to collisions, as high-speed doors are generally composed of flexible materials such as PVC or rubber, as opposed to standard overhead doors that are made of steel or aluminum.

This measure involves the installation of a high-speed overhead door in place of a standard overhead door. It is applicable to both existing buildings and new construction. The baseline is a standard speed overhead door. The full cost is $36,500 for a 16’ x 16’ door ($20,500 incremental cost over a standard, electrically operated rolling steel door[52]), savings are 87% over the baseline[53] and the service life is estimated to be 10 years.[54] Electric loads are assumed to be equivalent for both the baseline and the upgrade.

L-Shaped Vestibules

Measure Profile	
Applicable Building Types	All
Vintage	Existing & new
Costs	No incremental cost, estimated full cost of approximately $7,000 for a 50 ft^2 vestibule
Savings	20% compared to losses due to infiltration through a “straight” vestibule
Useful Life	25 years

L-shaped vestibules reduce unwanted heat transfer at the building envelope by minimizing mass transfer of outside air to the inside of the building and vice-versa. Typical applications include Retail buildings, Office buildings and Restaurants. Co-benefits include increased occupant comfort as a result of reduced drafts.

This measure involves upgrading a standard vestibule (in which the doors are aligned) with an L-shaped vestibule to reduce the penetration of air into the building. It is applicable to both existing buildings and new construction. The baseline is a standard vestibule in which the doors are aligned. The installed cost is estimated to be $7,040,[55] savings are estimated at 20% over the baseline[56] and the service life is estimated to be 25 years.[57]

[52] Personal communication, Bryan Crombeen, V.P.: Edwards Door Systems Ltd., London, ON.

[53] Savings based on assumed reduction in “open door” time. See Allocca, et. al (2003) and Appendix E for full calculation.

[54] Marbek estimate.

[55] RS Means Assemblies.

[56] Marbek estimate.

[57] BC Hydro QA Standard.

Turnstile Doors

Measure Profile	
Applicable Building Types	All
Vintage	Existing & new
Costs	Incremental cost of $6725
Savings	89% of energy lost due to infiltration when compared to a set of two standard doors
Useful Life	25 years

Turnstile doors reduce unwanted heat transfer at the building envelope by minimizing the amount of time that doors are left open, thus minimizing mass transfer of outside air to the inside of the building. Typical applications include high traffic exterior doorways such as those found in airports, shopping malls and large office buildings. The co-benefits include increased occupant comfort as a result of reduced drafts.

This measure involves the installation of a turnstile door in place of two standard swinging doors. It is applicable to both existing buildings and new construction. The baseline is two standard balanced doors. The installed cost is $19,675 door ($6,725 incremental cost), [58] savings are 89% over the baseline[59] and the service life is estimated to be 25 years.[60]

4.4.2 Heating, Ventilating and Air Conditioning

This study considered 17 heating, ventilating and air conditioning upgrade measures:

- Condensing Boilers
- Near-Condensing Boilers
- Condensing Unit Heaters
- High-Efficiency Rooftop Units
- Condensing Rooftop Units
- Absorption Heat Pumps
- Steam Plant Efficiency
- HVLS De-stratification Fans
- Heat Reflector Panels
- Programmable Thermostats
- Heat Recovery
- Demand Controlled Ventilation
- Demand Controlled Kitchen Ventilation
- Furnace/Boiler Tune-ups
- Condensing Furnaces
- Infrared Heaters
- Solar Preheated Make-up Air

[58] RS Means Assemblies.

[59] Savings based on assumed reduction in “open door” time. See Allocca, et. al (2003) and Appendix E for full calculation.

[60] BC Hydro QA Standard.

As applicable, the measures were evaluated at low, medium, and high hours of operation to reflect the range of commercial building types and climate regions found in the Union Service Area. Where available, cost and savings inputs have been drawn from data provided by Union Gas. An overview of each upgrade measure is presented below.

Condensing Boilers

Condensing boilers feature additional advanced heat exchanger designs and materials that extract more heat from the flue gases before they are exhausted. The temperature of the flue gases is reduced to the point where the water vapour produced during combustion condenses back into liquid form, releasing the latent heat, which improves energy efficiency. With 12% of the energy of a gas-fired boiler in the form of latent heat, this represents a significant energy savings potential. However, if the return water temperature to the boiler is above 60°C, condensation will not occur and savings will not be realized. This is particularly relevant to existing buildings that are typically designed with higher return water temperatures. The benefits of condensing boilers include superior performance, reduced operating costs through lower natural gas expenditures and fewer greenhouse gas emissions.

The analysis considered two baseline scenarios: standard efficiency boilers and near-condensing boilers. In both cases, the upgrade is applicable to existing buildings (at time of boiler replacement) and new construction, and the estimated service life is 25 years.[61] Note that this study assumes both baselines are present in all sub sectors (See appendices A and B).

<u>Standard Efficiency to Condensing</u>

Measure Profile	
Applicable Building Types	All
Vintage	Existing and new
Costs	$17/MBH incremental cost
Savings	14% of space heating energy
Useful Life	25 years

This measure involves upgrading to a high-efficiency condensing boiler with a thermal efficiency of 94% and a seasonal efficiency of 88%. The baseline is a standard efficiency boiler with a thermal efficiency of 80% and a seasonal efficiency of 76%.[62] The incremental cost is approximately $17 per MBH[63] and the savings are estimated to be 14% of space heating energy.

[61] Union Gas 2007-2009 DSM Plan, Appendix A, ASHRAE Applications Handbook – 2003, Chapter 36, Table 3.

[62] Union Gas 2007-2009 DSM Plan, Appendix A.

[63] Marbek database.

<u>Near-Condensing to Condensing</u>

Measure Profile	
Applicable Building Types	All
Vintage	Existing and new
Costs	$14/MBH incremental cost
Savings	8% of space heating energy
Useful Life	25 years

This measure involves upgrading to a high-efficiency condensing boiler with a thermal efficiency of 94% and a seasonal efficiency of 88%. The baseline is a near-condensing boiler with a thermal efficiency of 85% and a seasonal efficiency of 81%.[64] The incremental cost is approximately $14 per MBH,[65] and the savings are estimated to be 8% of space heating energy.

Near-Condensing Boilers

Near-condensing boilers offer superior heat exchange design and improved combustion technologies over standard efficiency units and generally have thermal efficiencies in the range of 85% to 88% without condensing. The benefits of near-condensing boilers include reduced operating costs through lower natural gas expenditures and fewer greenhouse gas emissions.

Measure Profile	
Applicable Building Types	All
Vintage	Existing and new
Costs	$3/MBH incremental cost
Savings	6% of space heating energy
Useful Life	25 years

This measure involves upgrading to a high-efficiency near-condensing boiler with a thermal efficiency of 85% and a seasonal efficiency of 81%. It is applicable to existing buildings (at time of boiler replacement) and new construction. The baseline is a standard efficiency boiler with a thermal efficiency of 80% and a seasonal efficiency of 76%. The incremental cost is approximately $3 per MBH,[66] the savings are estimated to be 6% of space heating energy and the service life is 25 years.[67]

Condensing Unit Heaters

High-efficiency condensing unit heaters feature a secondary heat exchanger to capture the latent heat in the exhaust air stream, separated combustion and a thermal efficiency of

[64] Terasen Gas DSM Potential Study 2004.

[65] Marbek database.

[66] Marbek database.

[67] Union Gas 2007-2009 DSM Plan, Appendix A, ASHRAE Applications Handbook – 2003, Chapter 36, Table 3.

up to 93%.[68] Typical applications include open high bay spaces such as warehouses, garages and industrial facilities. Conventional unit heaters generally have gravity vents and power vents and thermal efficiencies in the range of 76% to 83%.[69] The seasonal efficiency of gravity-vented units can be as low as 64%[70] when off-cycle losses and heated air exiting the building through the draft hood are taken in to consideration. The benefits of condensing unit heaters include superior performance, reduced operating costs through lower natural gas expenditures and fewer greenhouse gas emissions.

Measure Profile	
Applicable Building Types	Warehouse
Vintage	Existing and new
Costs	$8/MBH incremental cost
Savings	11% of space heating energy
Useful Life	20 years

This measure involves upgrading to a high-efficiency condensing unit heater with a thermal efficiency of 91%[71] and a seasonal efficiency of 89%.[72] It is applicable to existing buildings (at time of unit heater replacement) and new construction. The baseline is a conventional unit heater with a thermal efficiency of 80% and a seasonal efficiency of 79%.[73] The incremental cost is approximately $8 per MBH,[74] the savings are estimated to be 11% of space heating energy and the service life is 20 years.[75]

High-Efficiency Rooftop Units

High-efficiency rooftop units employ high-efficiency heat exchangers and modulating burners that can achieve part-load efficiencies as high as 86%.[76] High-efficiency rooftop units are able to maintain their steady state efficiencies by avoiding “on-off” cycling. They operate their heating sections continuously and modulate the heating output to match heating requirements. In contrast, standard gas-fired rooftop units generally have single or two-stage burners[77] and seasonal efficiencies of 73%. The benefits of high-efficiency rooftop units include better temperature control and the capability to maintain high comfort levels in multiple zones.

68 Reznor Model UEAS.

69 ACEEE.

70 NRCan.

71 Reznor Model UEAS 180.

72 Marbek estimate.

73 Based on NRCan’s proposed amendment to Canada’s Energy Efficiency Regulations.

74 RS Means Mechanical Cost Data 2007 and Reznor.

75 Union Gas 2007-2009 DSM Plan, Appendix A.

76 Personal communication with Engineered Air.

77 Union’s current high-efficiency rooftop unit measure inputs assume a minimum two-stage burner.

Measure Profile	
Applicable Building Types	All
Vintage	Existing and new
Costs	$5/MBH incremental cost
Savings	9% of space heating energy
Useful Life	20 years

This measure involves upgrading to a high-efficiency gas-fired rooftop unit with a fully modulating burner and a seasonal efficiency of 80%. It is applicable to existing buildings (at time of rooftop unit replacement) and new construction. The baseline is a standard rooftop unit with a seasonal efficiency of 73%. The incremental cost is approximately $5 per MBH,[78] the savings are estimated to be 9% of heating energy and the service life is 20 years.[79]

Condensing Rooftop Units

Condensing rooftop units are the most energy-efficient rooftop units on the market with thermal efficiencies in the range of 89% to 97%.[80] They include a secondary heat exchanger to extract the latent heat in the products of combustion. One of the challenges of this technology is providing a condensate drain system and a method of condensate freeze protection. The benefits of condensing rooftop units include reduced operating costs through lower natural gas expenditures and fewer greenhouse gas emissions.

Two suppliers of condensing rooftop units are Engineered Air and Custom Mechanical Equipment.

Engineered Air has recently developed a condensing rooftop unit with an efficiency of 90% to 94%.[81] The company is presently looking for sites to test the product in the field.

Custom Mechanical Equipment of Oklahoma manufactures custom-order high-efficiency packaged multi-zone units equipped with Lennox condensing furnaces (94.3 AFUE).

Measure Profile	
Applicable Building Types	All
Vintage	Existing and new
Costs	$25/MBH incremental cost
Savings	19% of space heating energy
Useful Life	20 years

This measure involves upgrading to a condensing gas-fired rooftop unit with a seasonal efficiency of 92%. It is applicable to existing buildings (at time of rooftop unit

[78] RS Means Mechanical Cost Data 2007.

[79] Union Gas 2007-2009 DSM Plan, Appendix A.

[80] ACEEE.

[81] Personal communication with Engineered Air.

replacement) and new construction. The baseline is a standard rooftop unit with a seasonal efficiency of 73%. The incremental cost is $25 per MBH,[82] the savings are estimated to be 19% of heating energy and the service life is 20 years.[83]

Gas Absorption Heat Pumps

Gas-fired absorption heat pumps (GAHP) are high-efficiency packaged heat pumps that use a water-ammonia absorption cycle to provide cooling and high-efficiency heating up to 126%.[84] The system uses outside air for heat rejection in the cooling mode and outside air as a heat source in the heating mode. Manufactured by Robur Corporation, they are available in several configurations including air-source, water source and heating only.

The GAHP-AR reversible air-source heat pump provides 120 MBH heating output at 140°F water temperature and an external ambient temperature as low as -20°F. In cooling mode, the unit has a capacity of 4.5 tons and is capable of providing chilled water as low as 38°F. However, one of the limitations is that the unit has a lower cooling efficiency than the standard electric vapour-compression cycle. The benefits of GAHPs include low electrical power requirements, modularity and outdoor installation.

Measure Profile	
Applicable Building Types	Small commercial, Multi-family
Vintage	Existing and new
Costs	$17/MBH incremental cost
Savings	25% of heating energy
Useful Life	15 years

For this analysis, we choose the Robur GAHP-A (heating only) air-source heat pump because it has the best chance for economic success given the low cooling efficiency of the reversible heat pump, and its ability to be combined with traditional boilers to improve overall heating efficiency. The GAHP-A has a seasonal efficiency of 105%[85] and is suitable for medium temperature applications up to 140 °F in small commercial buildings including fan coil systems, radiant in-floor systems and domestic hot water systems. It is applicable to existing buildings (at time of boiler replacement) and new construction. The baseline is a standard efficiency boiler with a thermal efficiency of 80% and a seasonal efficiency of 76%. The incremental cost is approximately $17 per MBH,[86] the savings are 24% of heating energy and the service life is 15 years.[87]

[82] RS Means and Personal communication with Engineered Air.

[83] Union Gas 2007-2009 DSM Plan, Appendix A.

[84] Robur GAHP-AR.

[85] GazMetro InformaTECH Vol 22, Number 2, June 2008.

[86] Marbek estimate and personal communication with D-B Cooling Systems Inc.

[87] BC Hydro QA Standard.

Steam Plant Efficiency Measures

Steam plant efficiency measures generally include combustion efficiency improvements, heat recovery, steam distribution and condensate return improvements, and equipment O&M improvements. The results of Enbridge Gas Distribution's Steam Plan Performance Test and Audit program show a potential of 13.7% natural gas savings with an average payback of 1.2 years.[88]

Measure Profile	
Applicable Building Types	Institutional including Hospital & University
Vintage	Existing and new
Costs	Average of 1.2 year payback
Savings	13.7% of heating energy
Useful Life	10 years

This measure involves the application of steam plant efficiency measures in large institutional buildings such as hospitals and universities. Since not all measures are applicable in any given project, the average results of the Enbridge program outlined above will be used in this analysis. The measures are applicable to both existing and new steam-heated buildings and the useful life is estimated to be an average of 10 years.

HVLS De-stratification Fans

High volume low speed (HVLS) de-stratification fans use large blades turning at low speeds to counter air stratification in facilities with high ceilings such as warehouses, retail stores and sports facilities. The proper application of HVLS fans can virtually eliminate stratification by gently driving the ceiling air downward and properly mixing the air to eliminate hot and cold spots. This results in reduced heat losses through the walls and roof during the heating season. In summer, the HVLS fan's breeze can lower the effective temperature of a space, allowing the cooling setpoint to be raised. The co-benefits include improved occupant comfort and indoor air quality.

Measure Profile	
Applicable Building Types	Warehouse and Retail
Vintage	Existing and new
Costs	$7,090/fan full cost
Savings	18% of space heating energy
Useful Life	15 years

This measure involves the installation of 24 ft. diameter HVLS fans. It is applicable to both new and existing buildings with high ceilings. The baseline is a high-ceiling warehouse with no ceiling fans. The installed cost is $7,090 per fan, the savings are 18% of the space heating energy[89] and the service life is 15 years.[90]

[88] The Enbridge Steam Saver Program Update To Year-End 2005, March 1, 2006.

[89] Analysis and assumptions based on *Energy Savings Associated with De-stratification Fans in Buildings With High Ceilings* (Draft), Caneta Research Inc., October 2007.

[90] Enbridge Gas Distribution DSM input assumptions.

Heat Reflector Panels

Heat reflector panels provide a low-E surface used to reflect infrared heat. This heat would normally be absorbed by walls situated behind radiators and partially lost to the outside through conduction. A layer of still air is also trapped behind the panels, reducing conductive heat losses through the wall.

Measure Profile	
Applicable Building Types	Older commercial buildings hot water or steam radiators/convectors
Vintage	Existing
Costs	$25/radiator full cost
Savings	3% of space heating energy
Useful Life	18 years

This measure involves the installation of heat reflector panels behind radiators in a commercial building. It is applicable to older existing buildings. The baseline is a radiator located against a standard wall. The full installed cost is estimated to be $25/unit,[91] savings are 3% of space heating energy[92] and the service life is estimated to be 18 years.[93] It should be noted that savings would likely be significantly reduced if this measure were installed in newer, better insulated buildings, as a portion of the savings are a result of increased thermal insulation provided by the panels.

Air-To-Air Heat Recovery

Energy recovery ventilators (ERV) and heat recovery ventilators (HRV) are air-to-air heat exchangers used to exchange the energy contained in normally exhausted building air with incoming outdoor ventilation air in commercial HVAC systems. HRVs recover the heat energy in the exhaust air, and transfer it to fresh air as it enters the building. ERVs also transfer the humidity level of the exhaust air to the intake air. HRVs and ERVs can capture between 70% and 80%[94] of the energy in air that is exiting the building. HRVs and ERVs can be stand-alone devices that operate independently, they can be built-in or they can be added to existing HVAC systems. It should be noted that Ontario's Building Code requires heat recovery ventilators in some instances where outdoor air is introduced at high volumes. Such systems are typical of modern health care buildings.[95] The co-benefits of air-to-air heat recovery include improved indoor air quality and reduced total HVAC equipment capacity.

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[91] Manufacturer information: www.novitherm.com.

[92] Union estimate.

[93] Enbridge Gas Distribution DSM input assumptions.

[94] www.uniongas.com.

[95] The Ontario Building Code requires heat recovery ventilators where:

"the quantity of the outdoor air supplied to the air duct distribution system is,

(a) more than 1 400 L/s, and

(b) more than 70% of the supply air quantity of the system."

See Government of Ontario. *Ontario Regulation 350/06 Building Code*. 2006.

Measure Profile	
Applicable Building Types	All
Vintage	Existing & new
Costs	$2.17/cfm incremental cost
Savings	50% of ventilation heating energy
Useful Life	15 years

This measure involves installing air-to-air heat recovery equipment to preheat make-up air in a commercial building. It is applicable to both existing buildings (at time of make-up air unit replacement) and new construction. The baseline is no heat recovery. The cost is $2.17 per cfm,[96] the savings are 50% of ventilation heating energy use[97] and the service life is 15 years.[98]

Programmable Thermostats

The use of programmable thermostats with packaged HVAC equipment provides improved control, scheduling and setpoint reset capability. The co-benefits include reduced maintenance and longer service life.

Measure Profile	
Applicable Building Types	Small Commercial
Vintage	Existing & new
Costs	$275/thermostat full cost
Savings	10% of space heating energy
Useful Life	15 years

This measure involves upgrading standard thermostats with programmable thermostats and scheduling the operation of the equipment based on occupancy requirements. It is applicable to both existing buildings and new construction and the baseline is a small commercial building with packaged rooftop units and standard thermostats. The full cost is estimated to be $275 per thermostat,[99] the savings are 10% of space heating energy use[100] and the service life is 15 years.[101]

Demand Controlled Ventilation

Demand controlled ventilation (DCV) uses CO_2 sensors to supply outdoor air (OA) based on the actual building occupancy, while preserving indoor air quality. Energy is saved because lower volumes of OA are introduced during periods of low occupancy. In

[96] RS Means Mechanical cost data.

[97] Marbek estimate.

[98] Union Gas 2007-2009 DSM Plan, Appendix A and BC Hydro QA Standard.

[99] Union estimate.

[100] CEEAM simulation.

[101] Personal communication, Union Gas / Enbridge DSM input assumptions.

practice, volumes of OA can often be reduced by as much as 50% in buildings with variable occupancy patterns. For most commercial buildings this reduction translates into a 10% savings in space heating energy use.

Measure Profile	
Applicable Building Types	All
Vintage	Existing & new
Costs	$1,500/air handling system full cost
Savings	10% of space heating energy
Useful Life	15 years

This measure involves upgrading standard ventilation controls with DCV. It is applicable to both existing buildings and new construction. The baseline is a large office building with standard ventilation controls. The cost is estimated to be $1,500 per air handling system,[102] the savings are 10% of space heating energy use[103] and the service life is 15 years.[104]

Demand Control Kitchen Ventilation

Commercial kitchen exhaust systems and associated makeup air systems continue to be designed and operated as constant volume ventilation systems, without the ability to respond to variations in cooking equipment usage. The application of a demand control kitchen ventilation (DCKV) system can achieve reductions in exhaust (and makeup) airflow when appliances are not being used to capacity. In a typical configuration, the DCKV system controls the speed of the exhaust fans and make-up air fan through variable frequency drives (VFDs) based on feedback from an infrared beam in the hood and temperature sensors located in the exhaust ducts. A 2004 DCKV pilot project in a Boston Pizza outlet showed an average 30% reduction in make-up air and a 2.1-year simple payback.[105]

Measure Profile	
Applicable Building Types	Food Service Operations
Vintage	Existing & new
Costs	$1.50/cfm full cost
Savings	30% of ventilation heating energy
Useful Life	20 years

This measure involves upgrading a standard kitchen ventilation system DCKV. It is applicable to both existing buildings and new construction. The baseline is a constant volume ventilation system. The cost is estimated to be $1.50 per cfm, the savings are approximately 30% of ventilation heating energy and the service life is 20 years.[106]

[102] Supplier information and RS Means.

[103] CEEAM simulation.

[104] BC Hydro QA Standard for building automation system.

[105] Evaluation of a Kitchen Ventilation Demand Control System Installed in a Boston Pizza, Fisher-Nickel, Inc, December 2004.

[106] Union Gas 2007-2009 DSM Plan, Appendix A.

Furnace/Boiler Tune-ups

Gas-fired equipment tune-ups involve inspecting the venting system, mechanical parts, filters (as applicable) and the interior of the combustion chamber. The burners are also generally removed and cleaned and the carbon monoxide level of the flue gas is assessed to ensure that the appliance is burning as cleanly as possible. Other checks include burner adjustments, testing the heat exchanger for carbon monoxide leaks, checking and adjusting all controls, setpoint adjustment, inspecting wiring and thermocouples, and making repair recommendations. For boiler systems, tune-ups may include a full combustion analysis. The benefits include improved efficiency, extending the lifetime of the equipment and improved safety and comfort.

Measure Profile	
Applicable Building Types	All
Vintage	Existing & new
Costs	$500/unit full cost
Savings	5% of space heating energy
Useful Life	2 years

This measure involves tuning up gas-fired appliances as part of a regular maintenance plan. It is applicable to both existing buildings and new construction. The baseline is a retail building with gas-fired rooftop units. The cost is estimated to be $500 per appliance,[107] the savings are 5% of space heating energy use[108] and the service life is two years.[109]

Condensing Furnaces

Condensing gas furnaces are the most energy-efficient furnaces available, with seasonal efficiencies between 89% and 97%, compared with AFUEs of about 60% for old furnaces and of 78% to 84% for standard efficiency units[110]. Most have burners similar to conventional furnaces, with draft supplied by an induced draft fan. Additional heat exchange surfaces made of corrosion-resistant materials (usually stainless steel) extract most of the heat remaining in the combustion by-products before they are exhausted. In this condensing heat exchange section, the combustion gases are cooled to a point where the water vapour condenses, thus releasing additional heat for space heating. The benefits of condensing unit heaters include superior performance, reduced operating costs through lower natural gas expenditures and fewer greenhouse gas emissions.

[107] Marbek estimate.

[108] Marbek estimate.

[109] Marbek estimate.

[110] Office of Energy Efficiency, Natural Resources Canada.

Measure Profile	
Applicable Building Types	Small Commercial
Vintage	Existing and new
Costs	$6/MBH incremental cost
Savings	15% of space heating energy
Useful Life	18 years

This measure involves upgrading to a high-efficiency condensing furnace with an AFUE of 94%. It is applicable to existing small commercial buildings (at time of furnace replacement) and new construction. The baseline is a standard furnace with an AFUE of 80%. The incremental cost is approximately $6 per MBH,[111] the savings are 15% of space heating energy and the service life is 18 years.[112]

Infrared Heaters

Infrared heating systems heat objects (including people) directly by radiant heat. The absorbed heat then warms the surrounding air. By comparison, a conventional forced air heating system heats the air and then circulates it so it can warm objects and people in the space. Since infrared heating heats objects directly, the ambient air temperature can be maintained at a lower temperature resulting in lower heat losses through building envelope.

Infrared heaters are categorized by high and low intensity. Tube-style heaters are usually low intensity; wall mounted heaters with ceramic refractory are high intensity. Tube heaters burn gas inside a long tube, creating radiant heat from the tube surface. A polished reflector directs the radiant heat down to the floor. Tube heaters start at 20,000 Btu/hr and have an efficiency of approximately 80%.[113] Typical applications include high ceiling and open spaces such as warehouses, garages, and recreation facilities. The co-benefits include improved comfort and quiet operation.

Measure Profile	
Applicable Building Types	Warehouse, Garage, Recreation Facility
Vintage	Existing and new
Costs	$3/MBH incremental cost
Savings	12% of space heating energy
Useful Life	20 years

This measure involves upgrading to an infrared heating system and maintaining a lower ambient air temperature in the space. It is applicable to existing buildings (at time of heater replacement) and new construction. The baseline is a standard unit heater with efficiency of 80%. The incremental cost is $3 per MBH,[114] the savings are 12%[115] of space heating energy and the service life is 20 years.[116]

[111] Supplier information and RS Means.

[112] ASHRAE, Union Gas Updated input assumptions (July 2008).

[113] Union Gas.

[114] RS Means Mechanical Cost Data 2007.

Solar Preheated Make-Up Air

A preheat solar air system uses solar energy to preheat outside air before it is introduced into a facility. In a typical system, a dark metal cladding mounted on the south-facing wall is used as a heat exchanger. Sunlight hitting the cladding heats the air, which is then drawn through thousands of small perforations into a narrow space between the wall and the building. The heated air rises up to a canopy plenum where it is drawn into the building or make-up air units for further heating and distribution. Typical applications include buildings with large south-facing exposures and a requirement for make-up air including warehouses, garages, multi-unit residential buildings, schools and central heating plants. The co-benefits include comfortable work environment, reduced air stratification and improved R-value of clad wall.

Measure Profile	
Applicable Building Types	Warehouse, Garage, Schools
Vintage	Existing and new
Costs	$40/ft^2 (of cladding)
Savings	18% of ventilation heating energy
Useful Life	20 years

This measure involves upgrading to a solar preheat make-up air system. It is applicable to existing buildings and new construction. The baseline is a standard make-up air unit with an efficiency of 80%. The cost is $40 per square foot of cladding,[117] the savings are estimated to be 18% of ventilation heating energy[118] and the service life is 20 years.[119]

4.4.3 Domestic Hot Water

The evaluation of domestic hot water (DHW) efficiency measures involved a study of the following gas-fired domestic hot water heating equipment:

- Condensing Water Heaters
- Condensing Storage Water Heaters
- Tankless Hot Water Heaters
- Drainwater Heat Recovery
- Low-flow Faucet Aerators and Showerheads
- Low-flow Pre-Rinse Spray Valves
- Solar Water Heating
- Booster Water Heaters

As applicable, measures were evaluated at low, medium, and high equivalent full-load hours to reflect the range of operation and loads commonly found in commercial

[115] Based on CEEAM simulation.

[116] Union updated input assumptions (July 2008).

[117] Marbek review of Renewable Energy Deployment Initiative (REDI) applications.

[118] RETScreen simulation.

[119] Marbek estimate.

buildings. In general, measures have been evaluated against a specific baseline to obtain a typical percentage savings as opposed to an absolute "per installation" savings. An overview of each upgrade measure is presented below.

Condensing Water Heaters

Condensing water heaters offer superior heat exchange design and improved combustion technologies over standard efficiency heaters resulting in thermal efficiencies up to 98%.[120] Its features include a separate storage tank, stainless steel heat exchanger, direct-vent sealed combustion and fully modulating combustion. Suitable applications include facilities with large hot water loads such as hotels, nursing homes and apartment buildings. The benefits of condensing water heaters include superior performance, reduced operating costs through lower natural gas expenditures and flexible venting.

Measure Profile	
Applicable Building Types	Hospitality, Health Care, & Multi-family
Vintage	Existing and new
Costs	$17/MBH incremental cost
Savings	22% of heating energy
Useful Life	24 years

This measure involves upgrading to a high-efficiency condensing water heater with a seasonal efficiency of 90%. It is applicable to existing buildings (at time of heater replacement) and new construction. The baseline is a standard water heater with a thermal efficiency of 80% and a seasonal efficiency of 70%. The incremental cost is approximately $17 per MBH,[121] the savings are estimated to be 22% of heating energy and the service life is 24 years.[122]

Condensing Storage Water Heaters

Condensing tank-type water heaters offer superior heat exchange design and improved combustion technologies over standard efficiency units resulting in thermal efficiencies up to 98%.[123] The heaters feature an integral storage tank, direct-vent sealed combustion, power burner and a multi-pass flue system. Suitable applications include all Commercial sub-sectors with medium to high hot water loads. The benefits of condensing water heaters include superior performance, reduced operating costs through lower natural gas expenditures and venting flexibility.

[120] Lochinvar Armor.

[121] RS Means Mechanical Cost Data 2007.

[122] BC Hydro QA Standard.

[123] Lochinvar Turbo Charger.

Measure Profile	
Applicable Building Types	All
Vintage	Existing and new
Costs	$13/MBH incremental cost
Savings	22% of heating energy
Useful Life	15 years

This measure involves upgrading to a high-efficiency condensing water heater with a seasonal efficiency of 90%. It is applicable to existing buildings (at time of heater replacement) and new construction. The baseline is a standard water heater with a thermal efficiency of 80% and a seasonal efficiency of 70%. The incremental cost is approximately $13 per MBH,[124] the savings are estimated to be 22% of heating energy under average operating conditions / duty cycle and the service life is 15 years.[125]

Tankless Water Heaters

Tankless water heaters heat water on demand, eliminating hot water storage. The gas burner is activated by the flow of water whenever a hot water valve is opened. They do not have standby losses (incurred by continuous use of energy to maintain water in a tank to a set temperature) and can be installed at a point-of-use or can replace conventional tank water heaters. Suitable applications include small and commercial buildings with medium to high hot water loads including restaurants, motels, laundries and car washes. Installation in areas with hard water lead to increased maintenance requirements for tankless water heaters due to heat exchanger fouling.

The efficiency of tankless water heaters depends on the water heater's characteristics and on the temperature of the water being heated. Operating efficiencies can be as high as 95% but are more typically in the 80% range. The gas requirements for tankless water heaters are much larger than for storage water heaters (2 to 4 times), so they may require larger gas lines and vents than conventional water heaters. The benefits of tankless water heaters include modularity, no standby losses and small space requirements.

Measure Profile	
Applicable Building Types	Small Commercial
Vintage	Existing and new
Costs	$15/MBH incremental cost
Savings	14% of heating energy
Useful Life	20 years

This measure involves upgrading a standard tank-type heater to tankless water heaters with a thermal efficiency of 82%.[126] It is applicable to existing buildings (at time of heater replacement) and new construction. The baseline is a standard water heater with a

[124] RS Means Mechanical Cost Data 2007.

[125] Union Gas Demand Side Management 2006 Evaluation Report.

[126] Takagi TM1.

thermal efficiency of 80% and a seasonal efficiency of 70%.[127] The incremental cost is approximately $15 per MBH,[128] the savings are estimated to be 14% of heating energy under average operating conditions / duty cycle and the service life is 20 years.[129]

Drainwater Heat Recovery

Drainwater heat recovery systems capture energy from warm wastewater and transfer it to cold make-up water at efficiencies up to 71%.[130] The technology consists of a shell-and-tube heat exchanger installed in a drainpipe. Typical applications include showers, dishwashers and laundries that have sustained levels of hot wastewater. Examples of this technology include the GFX system, which was originally developed with a grant from the U.S. Department of Energy and is currently manufactured by Doucette Industries, and the Powerpipe, manufactured by RenewABILITY Energy Inc.

Measure Profile	
Applicable Building Types	Apartments, Hotels, Kitchens, Laundries, Gyms
Vintage	Existing and new
Costs	$900/unit incremental cost
Savings	48% of shower water heating energy
Useful Life	20 years

This measure involves upgrading a hotel shower with a drainwater heat recovery system. It is applicable to existing buildings (at time of major plumbing renovations) and new construction. The baseline is a standard plumbing system with no heat recovery. The incremental cost is $900[131] per unit, the savings are 48%[132] of shower heating energy and the service life is estimated to be 20 years.[133]

Low-Flow Faucet Aerators and Showerheads

Low-flow faucet aerators lower the water flow to 0.5 to 2 gallons per minute (gpm) by introducing air into the water stream. The aerators create a fine water spray with a screen that is inserted in the faucet head. Low-flow showerheads use the same principle to achieve flow rates in the range of 1.5 to 2.2 gpm.

[127] Standing losses (and therefore seasonal efficiency) of a tank-type heater are heavily dependent on usage patterns. 70% has been taken as a sector-wide average.

[128] RS Means and supplier information.

[129] BC Hydro QA Standard.

[130] GFX dishwasher case study.

[131] RenewABILITY Energy Inc.

[132] Natural Resources Canada, Sustainable Buildings and Communities, *Drain Water Heat Recovery Characterization and Modeling*, July 19, 2007.

[133] Marbek estimate.

Measure Profile	
Applicable Building Types	All
Vintage	Existing and new
Costs	$5/faucet & $20/head
Savings	50% of hot water heating energy
Useful Life	10 years

This measure involves upgrading faucet aerators and showerheads with equivalent water efficiency units. It is applicable to existing buildings and new construction, with particular relevance to multi-unit residential buildings and hotels/motels. The baseline is a standard showerhead with a flow rate of 2.5 gpm and a standard faucet aerator with a flow rate of 2 gpm. The costs are $5 per faucet and $20 per showerhead,[134] the savings are 50% of hot water heating energy and the service life is 10 years.[135]

Low-Flow Pre-Rinse Spray Valves

Pre-rinse spray valves (also called a spray nozzle or spray head) are used by restaurant, cafeteria and kitchen workers to remove food from plates and other dishes prior to loading them in the dishwasher. New energy- and water-efficient valves utilize a "knife-edge" spray rather than a traditional "shower-type" spray to better focus the available energy and remove the food particles more efficiently. A traditional spray valve uses up to 5.0 gpm[136] of hot water, while efficient models use 1.6 gpm or less. The co-benefits include improved cleaning efficiency and performance.

Measure Profile	
Applicable Building Types	Food Service Operations
Vintage	Existing and new
Costs	$100/valve full cost
Savings	60% of hot water heating energy
Useful Life	5 years

This measure involves upgrading a standard pre-rinse spray valve with an equivalent water efficient 1.2 gpm spray valve. The technology is applicable to existing buildings and new construction with food service operations. The baseline is a standard spray valve with a flow rate of 2.7 gpm. The cost is $100 per valve, the savings are 60% of hot water heating energy and the service life is 5 years.[137]

Solar Water Heating Systems

Solar water heating systems use the energy of the sun to heat water. The primary components of a solar water heating system are a solar collector, a heat transfer fluid and

[134] Personal communication with Water Conservation Company Ltd.

[135] BC Hydro QA Standard.

[136] CEE Commercial Kitchens Initiative – Program Guidance on Pre-Rinse Spray Valves.

[137] Analysis and assumptions based on Region of Waterloo Pre-Rinse Spray Valve Pilot Study, Veritec Consulting Inc., January 2005.

a storage tank. Due to Canada's colder climate and the higher likelihood of freezing, active closed-loop systems are generally used. These systems use a pump to circulate a non-freezing heat transfer fluid through the collectors and then through a heat exchanger so that the thermal energy can be transferred to the water. Since solar heating systems are only able to partially offset hot water heating requirements, a conventional water heating system is generally used in conjunction with it to provide supplementary heat as required. A solar system is typically able to displace 20% of the total hot water energy use.

Measure Profile	
Applicable Building Types	All
Vintage	Existing and new
Costs	$9,000 per system
Savings	20% of hot water heating energy
Useful Life	15 years

This measure involves upgrading a standard hot heating system with a solar heating system. It is applicable to existing buildings and new construction. The baseline is a standard 100-gallon water heater with a thermal efficiency of 80% and a seasonal efficiency of 70%. The cost is approximately $9,000[138] per system, the savings are estimated to be 20% of hot water heating energy[139] and the service life is 15 years.[140]

Booster Water Heaters

Booster water heaters are used in applications requiring water temperatures above 140^{o}F including dishwashers, which typically require water up to 180^{o}F. Several technologies are commonly used including tank-type water heaters, tankless water heaters and small under-counter hot water boilers.

Measure Profile	
Applicable Building Types	Food Services
Vintage	Existing and new
Costs	$16/MBH incremental cost
Savings	16% of heating energy
Useful Life	15 years

This measure involves upgrading a standard tank-type booster heater to a tankless booster water heater with a thermal efficiency of 82%.[141] It is applicable to existing buildings with food services (at time of heater replacement) and new construction. The baseline is a standard water heater with a thermal efficiency of 80% and a seasonal efficiency of 70%.

[138] RS Means Mechanical Cost Data 2007.

[139] Marbek estimate.

[140] Marbek estimate based on measure life for standard tank water heaters.

[141] Takagi.

The incremental cost is approximately $16 per MBH,[142] the savings are estimated to be 16% of heating energy and the service life is 20 years.[143]

4.4.4 Cooking

This study considered four cooking appliance upgrade measures, primarily applicable in the Restaurant/Food Service sub sector:

- Efficient Gas Griddles
- Efficient Gas Broilers
- Efficient Gas Ovens
- ENERGY STAR® Fryers.

With the exception of broilers, food service appliances are generally evaluated in terms of "cooking efficiency," the ratio of energy added to food to the energy supplied to the appliance during cooking. Because broilers are not generally thermostatically controlled, and idling energy input rates are generally similar to energy input rates while cooking, cooking energy efficiency measured over the time span of a cooking event is less relevant. For this study, broilers are evaluated based on average hourly energy use using a standard duty cycle.

In general, measures have been evaluated against a specific baseline to obtain a typical percentage savings as opposed to an absolute "per installation" savings. An overview of each upgrade measure is presented below.

Efficient Gas Griddles

Standard griddles use approximately 86,100 kBtu (approximately 2,400 m^3 natural gas) per year and have efficiency levels that range from 25% to 45%. As with most commercial cooking appliances, a significant portion of griddle energy is lost during idling, as griddles are generally turned on all day and kept at cooking temperatures. A recent study estimated average griddle idling losses of 15 kBtu per hour.[144] Various new technologies, such as improved thermostat accuracy and control, infrared burners and enclosed heat pipes that connect the heat source directly to the griddle plate, have been developed. Under ideal operating conditions, these innovations can improve griddle cooking efficiency to levels above 45%, while reducing idling losses.

Measure Profile	
Applicable Building Types	All
Vintage	Existing and new
Costs	$1,150/unit incremental cost
Savings	20% compared with standard gas griddle
Useful Life	10 years

142 RS Means and supplier information.

143 BC Hydro QA Standard.

144 *Commercial Cooking Appliance Technology Assessment*. Prepared for the Food Service Technology Center (FSTC) by Don Fisher, 2002.

This measure involves upgrading to an efficient gas griddle with a cooking efficiency of 40% at the time of stock turnover. The baseline is a standard gas griddle with a cooking efficiency of 32%.[145] The incremental cost is approximately $1,150 per unit,[146] measure savings are estimated to be 20% compared to the baseline and the service life is 10 years.[147]

Efficient Gas Broilers

Depending on the type, broilers use approximately 115,000 kBtu to 210,000 kBtu (approximately 3,200 m^3 to 5,900 m^3 gas) per year. They tend to have high energy use, low efficiency levels and are often one of the most expensive appliances to operate in a commercial kitchen.[148] Past broiler efficiency strategies have dealt with methods of reducing the input energy when the broiler is idle; however, none have proven to be commercially successful. In addition, the distinctive flavour and appearance of broiled food is often desirable and consequently, switching to other, more efficient cooking methods is typically not a viable option.

Measure Profile	
Applicable Building Types	All
Vintage	Existing and new
Costs	$200/unit incremental cost
Savings	19% compared with standard gas broiler
Useful Life	10 years

This measure involves upgrading to an efficient gas broiler with an average gas use of 69 MJ/hr at the time of stock turnover. The baseline is a standard gas griddle with an average gas use of 85 MJ/hr.[149] In general, commercial broiler prices vary based on non-energy features and are not directly related to the unit's energy efficiency. This study assumes the most efficient units have a small incremental cost ($200) over baseline models.[150] Measure savings are estimated to be 19% and the service life of a commercial broiler is estimated to be 10 years.[151]

Efficient Gas Ovens

Standard gas ovens use approximately 62,400 kBtu (approximately 1,750 m^3 gas) per year and have efficiency levels that range from 30% to 40%.[152] Various technologies, such as improved insulation, infrared burners and improved air circulation have been

[145] U.S. EPA ENERGYSTAR Commercial food service equipment best practice tools. www.energystar.gov/index.cfm?c=commercial_food_service.commercial_food_service.

[146] U.S. EPA ENERGYSTAR.

[147] Marbek estimate,

[148] Fisher, 2002.

[149] U.S. EPA ENERGY STAR® Commercial food service equipment best practice tools.

[150] U.S. EPA ENERGY STAR®.

[151] U.S. EPA ENERGY STAR®.

[152] Fisher, 2002.

developed to improve both cooking characteristics and oven efficiency. Combination ovens, which include steam injection, claim efficiencies of up to 60%.[153]

Measure Profile	
Applicable Building Types	All
Vintage	Existing and new
Costs	$1,500/unit incremental cost
Savings	25% compared with standard gas oven
Useful Life	10 years

This measure involves upgrading to an efficient gas oven with a cooking efficiency of 45% at the time of stock turnover. The baseline is a standard gas oven with a cooking efficiency of 35%.[154] The incremental cost is approximately $1,500 per unit,[155] measure savings are estimated to be 25% compared to the baseline and the service life is 10 years.[156]

ENERGY STAR® Gas Fryers

Standard gas fryers have efficiencies in the range of 25% to 50% and use approximately 74,900 kBtu (approximately 2,100 m^3 natural gas) per year.[157] Various new technologies, such as infrared burners, powered burners, recirculation tubes and fry pot insulation, have been developed that improve fryer efficiency to roughly 50% to 65%.

Infrared (IR) burners employ a fine honeycomb matrix to evenly disperse the fuel/air mixture across the burner surface. Combustion takes place close to the burner surface, causing it to become red hot and emit infrared radiation to the surrounding heat-transfer-tube walls. IR burners currently represent 5% to 10% of the gas fryers in the marketplace.[158]

Measure Profile	
Applicable Building Types	All
Vintage	Existing and new
Costs	$1,100/unit incremental cost
Savings	30% compared with standard gas fryer
Useful Life	10 years

This measure involves upgrading to an ENERGY STAR® fryer with a cooking efficiency of 50% at time of stock turnover. The baseline is a standard fryer with an efficiency of 35%. Incremental cost is estimated at $1,100[159] and savings are 30%

[153] U.S. EPA ENERGY STAR®.

[154] Fisher, 2002.

[155] Fisher, 2002.

[156] Marbek estimate.

[157] Fisher, 2002.

[158] Fisher, 2002.

[159] U.S. EPA ENERGY STAR®.

compared to the baseline technology. The service life of a fryer is estimated to be 10 years.[160]

4.4.5 Whole Building

This study considered three whole building upgrade measures:

- Building Recommissioning
- Advanced Building Automation Systems
- High-Performance New Construction.

An overview of each upgrade measure is presented below.

Building Recommissioning

Retrocommissioning is the process of applying building commissioning procedures to an existing building in operation. This process ensures that the previously commissioned systems are still maintained and operated in accordance with the original design intent. It is also an opportunity to optimize operations beyond the intent of the original designers using the experience of operating the building as a guide. The U.S. Green Building Council (USGBC) recognized the importance of retrocommissioning by awarding it an innovation point in its Leadership for Energy and Environmental Design (LEED) for existing buildings (LEED-EB) ratings system.

The cost and energy savings of retrocommissioning depends on a building's complexity; studies indicate, however, that the process is cost effective. In 2004, Lawrence Berkeley National Laboratory (LBNL) compiled and synthesized extensive published and unpublished data from building commissioning projects undertaken across the U.S., establishing the largest available collection of standardized information on commissioning experience. The results showed the median cost of retrocommissioning was $0.27 per square foot, yielding whole-building energy savings of 15% and payback times of 0.7 years.[161] Other benefits of the process included improved IAQ, greater asset values, higher worker productivity and increased equipment life.

Measure Profile	
Applicable Building Types	All
Vintage	Existing
Costs	\$0.35/ft^2 full cost
Savings	15% of whole building energy use
Useful Life	5 years

This measure involves applying the retrocommissioning process to an existing building. The baseline is a typical large office building. The cost is estimated to be \$0.35/ft^2,[162] the savings are 15% of whole-building energy use[163] and the service life is 5 years.[164]

[160] U.S. EPA ENERGY STAR®.

[161] The Cost-effectiveness of Commercial Buildings Commissioning, LBNL, December 2004.

[162] The Cost-effectiveness of Commercial Buildings Commissioning, LBNL, December 2004.

Advanced Building Automation Systems

Advanced building automation systems (BAS) are able to automatically detect anomalies in building operations and can automate building diagnostics as well. These systems typically take data on how energy systems are performing in a building, analyze them using logic and physical modeling to detect deviations from expected performance and use built-in logic to suggest the cause of the deviation.[165] In addition, advanced BAS have improved predictive, self-tuning control algorithms that help to minimize the need for bypass or override of the BAS. Energy savings generally result from re-instituting equipment scheduling, expanded control to lighting and VAV boxes, instituting integrated control strategies and improving self-tuning diagnostics.

Measure Profile	
Applicable Building Types	All
Vintage	Existing
Costs	Full cost of $0.90/ft^2
Savings	10% of total energy use
Useful Life	10 years

This measure involves installing an advanced BAS or upgrading an existing BAS with an advanced BAS. It is applicable to existing buildings. The baseline is a typical large commercial building. The cost is estimated to be $0.90/ft^2, the savings are 10% of total building energy use and the service life is 10 years.[166]

High-Performance New Building Construction

High-performance new building construction refers to new high-efficiency buildings that are designed using the integrated design process. Through the application and integration of energy-efficiency technologies and design approaches, high-efficiency buildings that use this process can achieve substantial improvements over conventional new buildings. The co-benefits include lower operations and maintenance costs and enhanced occupant productivity and health.

Baseline new construction is assumed to follow the energy requirements of the Ontario Building Code 2006.

Two energy-efficiency upgrade options were evaluated for new construction:

- New Commercial Building – 25% more efficient than current standards
- New Commercial Building – 40% more efficient than current standards.

[163] Marbek database.

[164] Marbek estimate.

[165] E Source E News. *Automated Building Diagnostics: Improving Electricity Performance and Occupant Comfort*. ER-01. November 18, 2001.

[166] Marbek estimates.

New Commercial Building – 25% More Efficient than Current Standards

A new commercial building that is 25% more efficient than current design practice is achievable using an integrated design approach (IDA). The IDA approach to new building design is predicated on a systematic application of energy measures to all end uses at the design stage. This includes targeting the building envelope, lighting, fans and pumps and, finally, the heating and cooling plants.

Measure Profile	
Applicable Building Types	All
Vintage	New
Costs	$2.5/ft^2 incremental cost
Savings	25%
Useful Life	25 years

This measure involves designing a new commercial building that is 25% more efficient than current design practice. The baseline is a building designed to the energy requirements in the Ontario Building Code 2006 (OBC). The incremental cost is estimated to be $2.50/ft^2, the savings are 25% of total building energy use and the service life is 25 years.[167]

New Commercial Building – 40% More Efficient than Current Standards

A new commercial building that is 40% more efficient than current design practice will require a very high-performance design, equivalent to the energy performance of a LEED Gold building. This requires a full IDA that takes advantage of costs trade-offs from equipment downsizing. The design will require the most energy-efficient technologies, extremely efficient lighting designs and heating/cooling plants with very high part-load efficiencies.

Measure Profile	
Applicable Building Types	All
Vintage	New
Costs	$4.50/ft^2 incremental cost
Savings	40%
Useful Life	25 years

This measure involves designing a new commercial building that is 40% more efficient than current design practice. The baseline is a building designed to the energy requirements in the OBC. The incremental cost is estimated to be $4.50/ft^2, the savings are 40% of total building energy use and the service life is 25 years.[168]

[167] The Costs and Financial Benefits of Green Buildings: A Report to California's Sustainable Building Task Force, October 2003.

[168] The Costs and Financial Benefits of Green Buildings: A Report to California's Sustainable Building Task Force, October 2003.

5 ECONOMIC POTENTIAL FORECAST

5.1 INTRODUCTION

This section presents the Commercial sector Economic Potential Forecast for the study period (2007 to 2017). The Economic Potential Forecast estimates the level of natural gas consumption that would occur if all building systems and equipment were upgraded to the level that is cost effective. In this study, “cost effective” means that the technology upgrade passes the measure TRC test, as discussed in Section 4.

The discussion in this section is organized into the following subsections:

- Major Modelling Tasks
- Technologies Included in Economic Potential Forecast
- Presentation of Results
- Interpretation of Results.

5.2 MAJOR MODELLING TASKS

By comparing the results of the Commercial sector Economic Potential Forecast with the Reference Case, it is possible to determine the aggregate level of potential natural gas savings within the Commercial sector, as well as identify which specific building segments, vintages and end uses provide the most significant savings opportunities.

To develop the Commercial sector Economic Potential Forecast, the following tasks were completed:

- The measure TRC results for each of the energy-efficiency upgrades presented in Exhibit 4.4 were reviewed.

- Technology upgrades that had positive measure TRC results were selected for inclusion either on a “full cost” or “incremental” basis. Technical upgrades passing the measure TRC test on a “full cost” basis were implemented in the first forecast year. Those upgrades that only passed the measure TRC test on an “incremental” basis were introduced as the existing stock reached the end of its useful life. If more than one cost-effective measure existed for the same end-use application, the study selected the most energy-efficient one.

- Energy use within each of the building segments was modelled with the same energy models that were used to generate the Reference Case. However, for this forecast, the remaining standard efficiency technologies included in the Reference Case forecast were replaced with the most efficient “technology upgrade option” that passed the measure TRC test.

- When more than one upgrade option was applied to a given end use, the first measure selected was the one that reduced the energy load. For example, measures to reduce the overall water heating load (e.g., low-flow showerheads and faucet aerators) would be applied before a high-efficiency water heater or boiler.

5.3 TECHNOLOGIES INCLUDED IN ECONOMIC POTENTIAL FORECAST

Exhibit 5.1 provides a listing of the technologies selected for inclusion in this forecast. In each case, the exhibit shows the following:

- End use affected
- Upgrade option(s) selected
- Sub sector(s) to which the upgrade options were applied
- Rate at which the upgrade options were introduced into the stock.

Exhibit 5.1: Technologies Included in Economic Potential

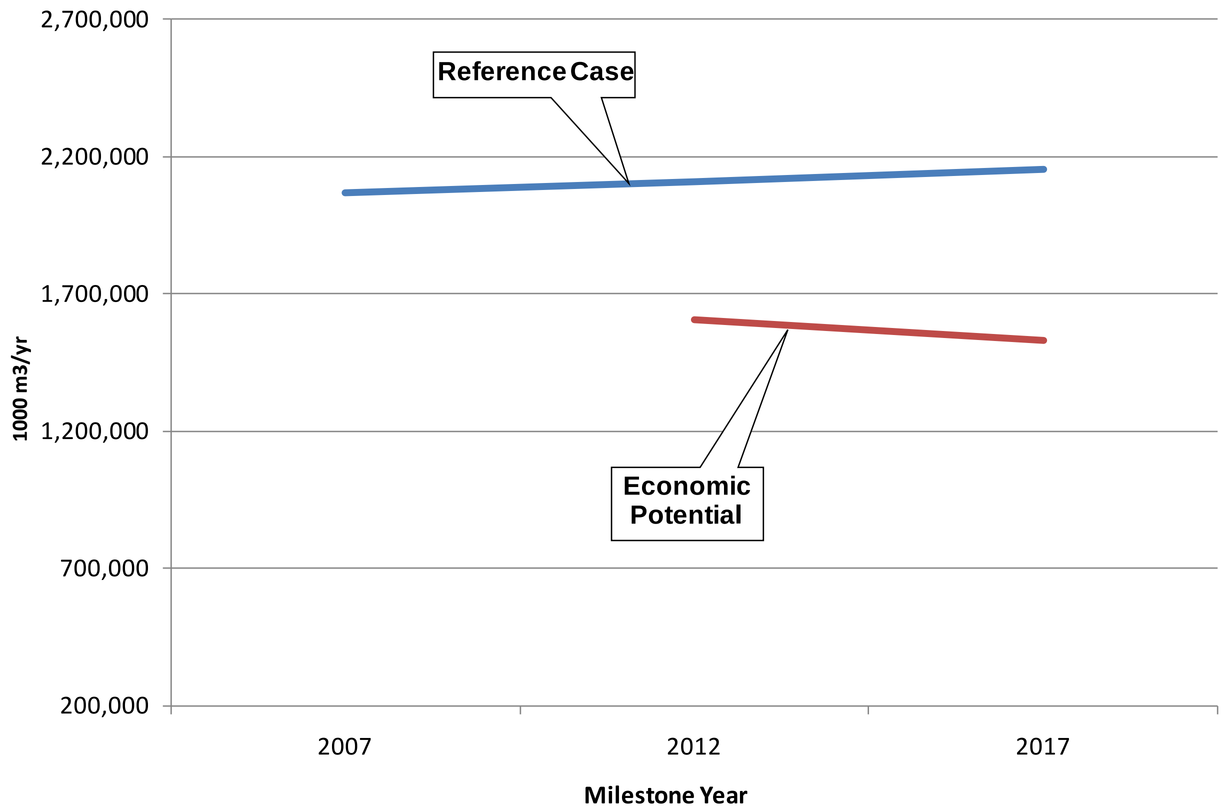
End Use	Upgrade Option	Applicability of Upgrade Options by Sub Sector	Rate of Stock Introduction
Space Heating	High-performance glazing	All existing	At rate of replacement
	Roof insulation	All existing	At rate re-roofing
	Air sealing	All existing	Immediate
	Air curtains	Existing Retail, Warehouse	Immediate
	Demand controlled ventilation	Existing School, Small Office, Large Office,	Immediate
	Demand controlled kitchen ventilation	Existing Restaurant	Immediate
	Air-to-air heat recovery	Existing Warehouse, University/College, Contract University/College, Small Hotel, Retail, Mid-rise Apartment, Nursing Home, Large Hotel, Hospital, Contract Hospital, High-Rise Apartment, Contract Apartment	Immediate
	Building Recommisioning	All Existing	Immediate
	De-stratification fans	Existing Warehouse	Immediate
	Steam plant measures	Existing Contract Hospital, Hospital, Contract University/College, University/College	Immediate
	Heat reflector panels	Existing Contract Apartment, High-rise Apartment, Mid-rise Apartment	Immediate
	Condensing boilers	All Existing	At rate of replacement
	Condensing unit heaters	Existing Warehouse	At rate of replacement
	Condensing rooftop units	All Existing	At rate of replacement
	Condensing furnace	Existing Small Office, Retail	At rate of replacement
DHW	Faucet aerators and low-flow showerheads	All Existing	Immediate
	Pre-rinse spray valve	Existing Restaurant	Immediate
	Condensing water heater	All Existing	At rate of replacement
	Condensing storage water heater	All Existing	At rate of replacement

End Use	Upgrade Option	Applicability of Upgrade Options by Sub Sector	Rate of Stock Introduction
Cooking	Efficient gas broiler	All Existing	At rate of replacement
	Efficient gas griddle	All Existing	At rate of replacement
	ENERGY STAR® gas fryer	All Existing	At rate of replacement
Space Cooling	Building recommissioning	Existing Hospital, Contract Hospital, University/College, Contract University/College, Large Office	Immediate
Other	Building recommissioning	All Existing	Immediate
New Construction	High-performance new construction – 40% more efficient	All New	At rate of new building construction

5.4 PRESENTATION OF RESULTS

Exhibit 5.2 compares the Reference Case and Economic Potential Forecast levels of energy consumption in the Commercial sector. As illustrated, under the Reference Case Commercial sector natural gas consumption would grow from the Base Year level of approximately 2,067,000,000 m^3/yr. to 2,157,000,000 m^3/yr. by 2017. This contrasts with the Economic Potential Forecast in which natural gas consumption would decrease to approximately 1,532,000,000 m^3/yr., a difference of approximately 625,000,000 m^3/yr., or 29% by 2017.

Exhibit 5.2: Reference Case versus Economic Potential - Natural Gas Consumption for the Total Union Service Area (1000 m^3/yr.)



5.4.1 Natural Gas Savings

Further detail on the total potential natural gas savings provided by the Economic Potential Forecast is provided in the following exhibits:

- Exhibits 5.3, 5.4 and 5.5 present results by end use and milestone year for the total Union Service Area in both tabular and graphic forms.
- Exhibits 5.6, 5.7 and 5.8 present results by end use and milestone year for the Southern service region in both tabular and graphic forms.
- Exhibits 5.9, 5.10 and 5.11 present results by end use and milestone year for the Northern service region in both tabular and graphic forms.
- Exhibit 5.12 and 5.13 present the results in 2017 by sub sector and end use for the Southern and Northern service regions, respectively.
- Exhibit 5.14 and 5.15 present the results in 2017 disaggregated by sub sector and building vintage for the Southern and Northern service regions, respectively.

Exhibit 5.3: Natural Gas Savings by End Use and Milestone Year, Total Union Gas Service Area – Economic Potential (1000 m^3/yr.)

Sub Sector	Milestone Year	Total	Space Heating	Water Heating	Cooking	Space Cooling	Other
Large Office	2012	34,602	29,280	3,049	27	26	2,220
	2017	41,908	35,243	3,787	60	26	2,792
Small Office	2012	66,873	60,052	4,440	49	0	2,332
	2017	83,975	75,182	5,798	105	0	2,890
Retail	2012	42,912	37,795	3,753	325	0	1,039
	2017	56,780	50,118	4,633	693	0	1,336
Large Hotel	2012	3,761	1,944	1,600	48	0	169
	2017	4,656	2,581	1,769	99	0	207
Small Hotel/Motel	2012	1,912	1,137	665	4	0	105
	2017	2,411	1,490	785	9	0	127
Contract Hospital	2012	14,857	10,169	3,480	82	45	1,081
	2017	17,250	12,174	3,697	169	49	1,161
Hospital	2012	6,306	4,823	1,216	36	11	220
	2017	7,572	5,934	1,304	75	13	246
Nursing Home	2012	15,544	10,346	4,265	212	0	721
	2017	19,765	13,755	4,708	436	0	867
School	2012	35,800	32,846	2,670	134	0	150
	2017	41,184	37,612	3,113	278	0	181
Contract University/College	2012	20,771	16,085	3,247	212	88	1,140
	2017	25,246	20,030	3,439	431	88	1,258
University/College	2012	4,163	3,388	588	33	17	137
	2017	5,078	4,216	624	67	17	153
Restaurant/Food Service	2012	19,927	12,366	5,580	1,921	0	59
	2017	24,606	14,149	6,442	3,942	0	72
Warehouse	2012	18,695	17,272	904	10	0	508
	2017	22,960	21,172	1,142	21	0	625
Contract Apartment	2012	2,016	1,326	656	2	0	33
	2017	2,500	1,704	753	3	0	40
High-rise Apartment	2012	47,062	31,744	14,516	39	0	764
	2017	58,550	40,819	16,717	80	0	934
Mid-rise Apartment	2012	28,096	18,907	8,932	36	0	221
	2017	35,004	24,276	10,382	75	0	270
Other Buildings	2012	78,359					
	2017	96,855					
Other Contract Institutional Buildings	2012	62,847					
	2017	79,076					
Total	2012	504,505	289,480	59,563	3,170	188	10,898
	2017	625,376	360,454	69,094	6,544	193	13,160

Exhibit 5.4: 2017 Natural Gas Savings by End Use, Total Union Gas Service Area – Economic Potential (1000 m^3/yr.)

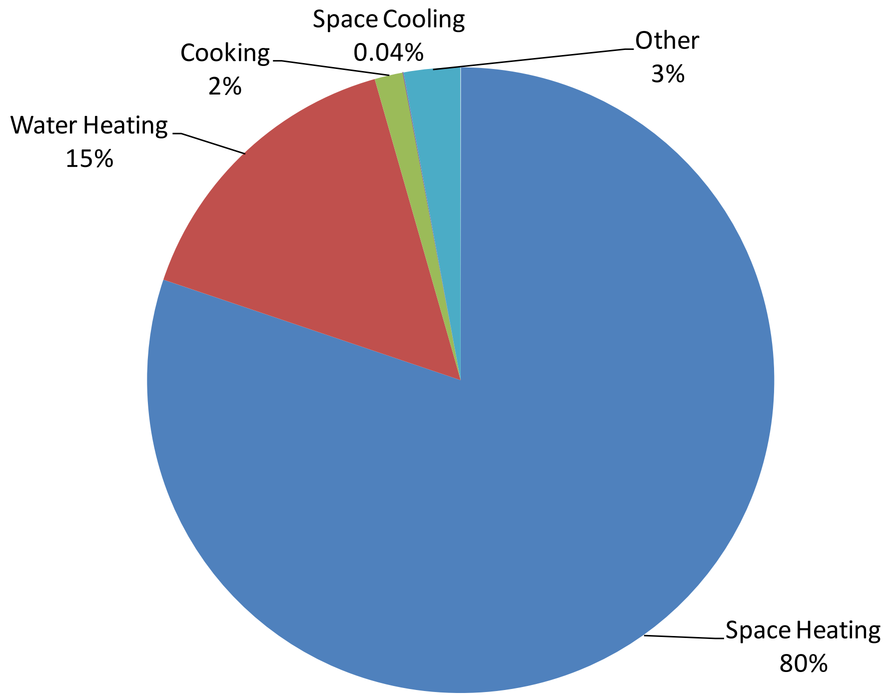


Exhibit 5.5: 2017 Natural Gas Savings by Sub sector, Total Union Gas Service Area – Economic Potential (1000 m^3/yr.)

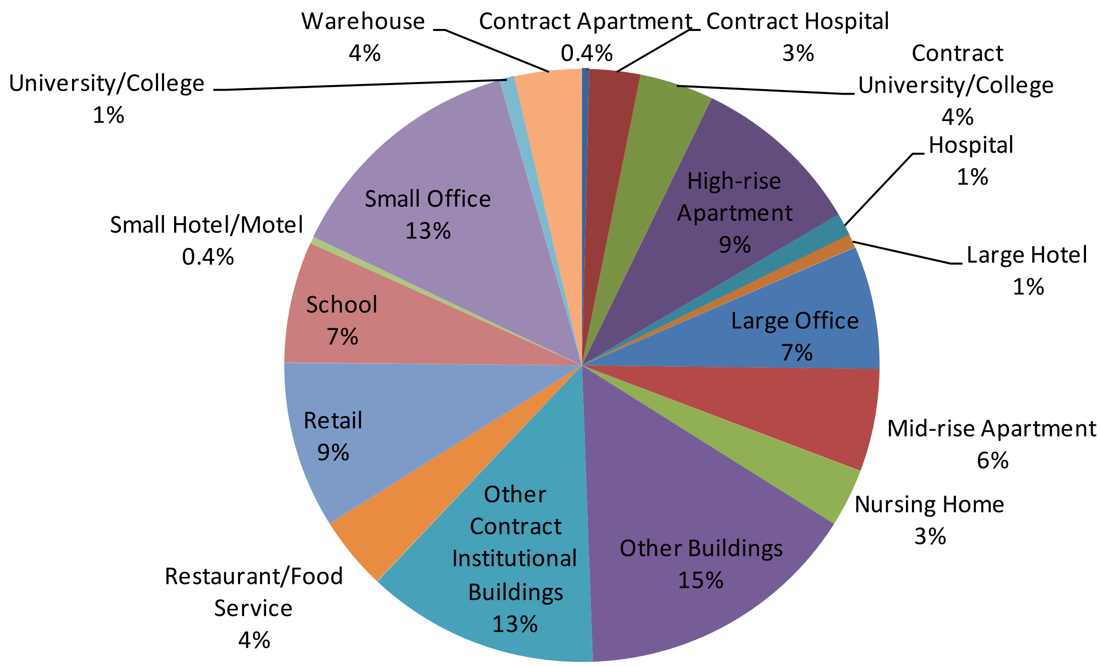


Exhibit 5.6: Natural Gas Savings by End use and Milestone Year, Southern Service Region – Economic Potential (1000 m^3/yr.)

Sub Sector	Milestone Year	Total	Space Heating	Water Heating	Cooking	Space Cooling	Other
Large Office	2012	14,454	11,948	1,406	12	26	1,061
	2017	17,082	14,011	1,709	27	26	1,309
Small Office	2012	25,048	22,169	1,875	21	0	984
	2017	31,597	27,868	2,459	45	0	1,225
Retail	2012	38,611	33,928	3,436	298	0	949
	2017	50,956	44,877	4,230	633	0	1,215
Large Hotel	2012	2,881	1,445	1,265	38	0	133
	2017	3,547	1,913	1,394	78	0	162
Small Hotel/Motel	2012	1,356	762	510	3	0	81
	2017	1,700	997	599	7	0	98
Contract Hospital	2012	13,099	8,886	3,125	73	44	970
	2017	15,169	10,616	3,314	151	48	1,041
Hospital	2012	2,640	1,944	569	16	9	102
	2017	3,133	2,375	604	32	10	112
Nursing Home	2012	10,209	6,616	2,951	147	0	494
	2017	12,889	8,757	3,243	300	0	588
School	2012	22,503	20,519	1,793	90	0	101
	2017	25,667	23,287	2,074	186	0	120
Contract University/College	2012	18,386	14,140	2,937	191	86	1,031
	2017	22,299	17,579	3,107	390	86	1,137
University/College	2012	3,345	2,696	491	28	16	114
	2017	4,066	3,346	520	56	16	128
Restaurant/Food Service	2012	17,366	10,629	4,972	1,712	0	53
	2017	21,435	12,130	5,732	3,508	0	64
Warehouse	2012	17,611	16,248	867	10	0	487
	2017	21,612	19,900	1,094	20	0	598
Contract Apartment	2012	2,016	1,326	656	2	0	33
	2017	2,500	1,704	753	3	0	40
High-rise Apartment	2012	42,418	28,397	13,287	36	0	698
	2017	52,673	36,467	15,281	73	0	852
Mid-rise Apartment	2012	22,809	15,156	7,440	30	0	184
	2017	28,327	19,415	8,627	62	0	223
Other Buildings	2012	67,771					
	2017	83,707					
Other Contract Institutional Buildings	2012	57,758					
	2017	72,537					
Total	2012	380,280	196,810	47,579	2,707	182	7,474
	2017	470,896	245,243	54,740	5,573	186	8,911

Exhibit 5.7: 2017 Natural Gas Savings by End Use, Southern Service Region – Economic Potential (1000 m³/yr.)

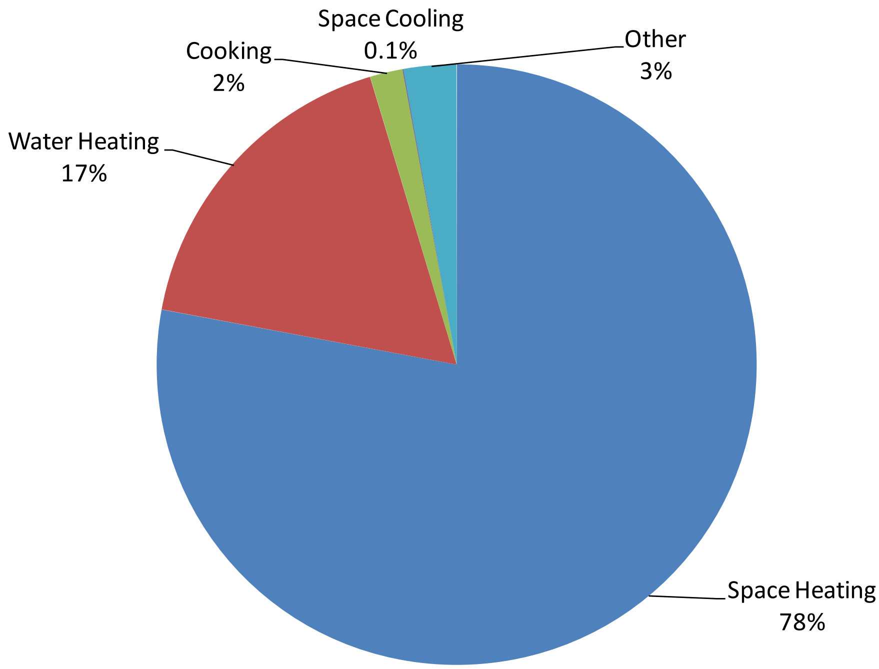


Exhibit 5.8: 2017 Natural Gas Savings by Sub sector, Southern Service Region – Economic Potential (1000 m³/yr.)

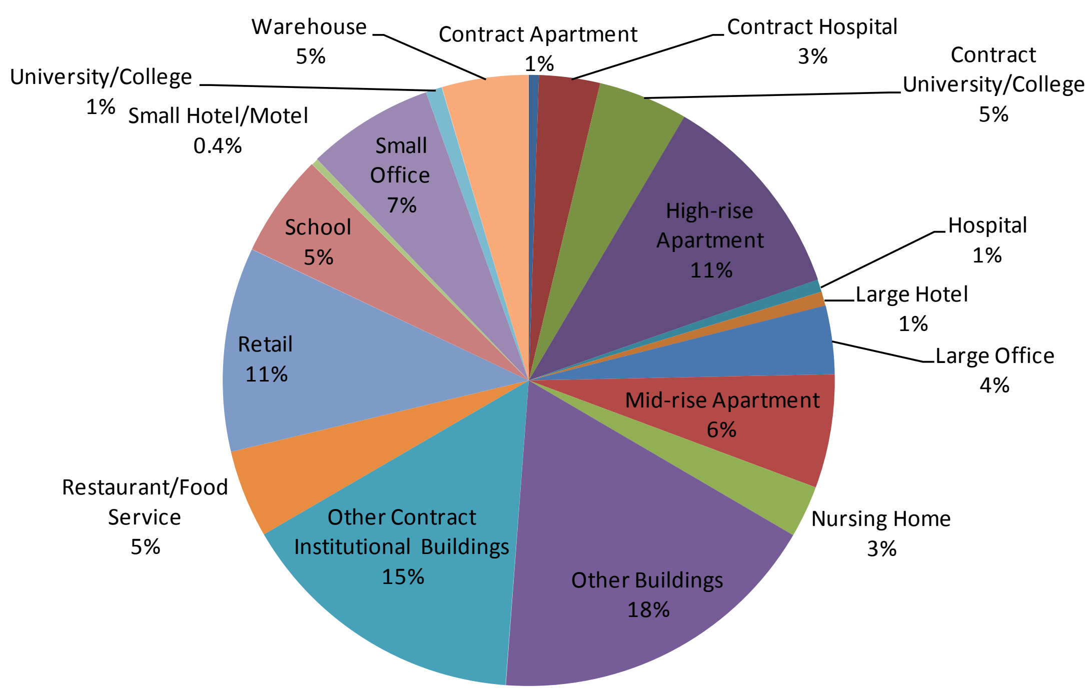


Exhibit 5.9: Natural Gas Savings by End use and Milestone Year, Northern Service Region – Economic Potential (1000 m^3/yr.)

Sub Sector	Milestone Year	Total	Space Heating	Water Heating	Cooking	Space Cooling	Other
Large Office	2012	20,148	17,332	1,644	14	0	1,159
	2017	24,826	21,232	2,078	33	0	1,483
Small Office	2012	41,825	37,883	2,566	28	0	1,348
	2017	52,379	47,314	3,339	61	0	1,664
Retail	2012	4,301	3,866	317	27	0	90
	2017	5,824	5,241	403	60	0	121
Large Hotel	2012	880	499	335	10	0	36
	2017	1,108	668	375	21	0	45
Small Hotel/Motel	2012	556	375	155	1	0	24
	2017	711	493	186	2	0	30
Contract Hospital	2012	1,758	1,283	355	8	1	110
	2017	2,081	1,558	383	17	2	121
Hospital	2012	3,667	2,878	648	21	2	118
	2017	4,440	3,559	700	43	3	134
Nursing Home	2012	5,335	3,730	1,314	65	0	227
	2017	6,876	4,998	1,464	135	0	279
School	2012	13,298	12,327	878	44	0	50
	2017	15,517	14,325	1,040	92	0	61
Contract University/College	2012	2,385	1,945	309	20	2	109
	2017	2,946	2,450	332	41	2	121
University/College	2012	819	693	97	5	1	23
	2017	1,012	870	104	11	1	26
Restaurant/Food Service	2012	2,560	1,736	608	209	0	7
	2017	3,171	2,019	710	434	0	8
Warehouse	2012	1,084	1,025	38	0	0	21
	2017	1,347	1,271	48	1	0	27
High-rise Apartment	2012	4,644	3,346	1,229	3	0	66
	2017	5,876	4,352	1,436	7	0	82
Mid-rise Apartment	2012	5,287	3,752	1,492	6	0	38
	2017	6,677	4,861	1,756	13	0	47
Other Buildings	2012	10,588					
	2017	13,148					
Other Contract Institutional Buildings	2012	5,090					
	2017	6,539					
Total	2012	124,225	92,670	11,984	463	5	3,424
	2017	154,480	115,211	14,355	971	7	4,249

Exhibit 5.10: 2017 Natural Gas Savings by End Use, Northern Service Region – Economic Potential (1000 m^3/yr.)

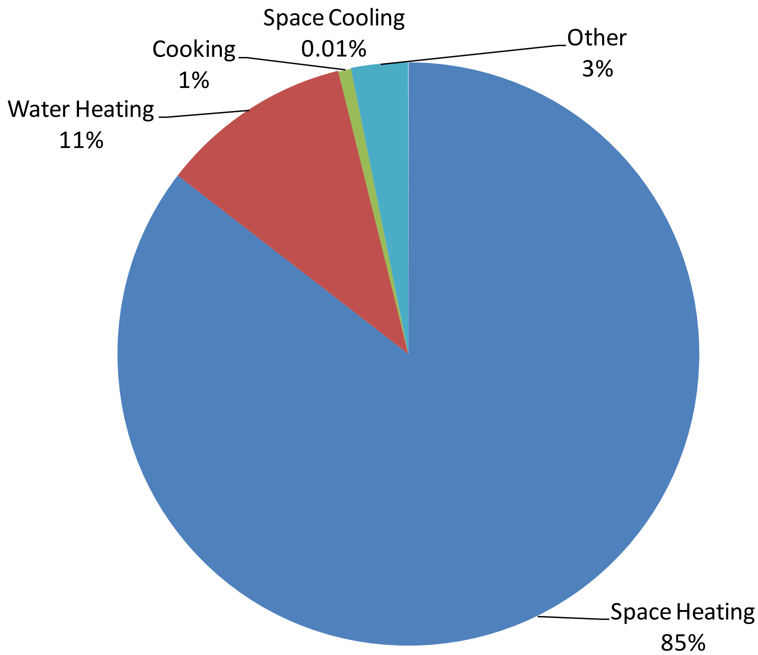


Exhibit 5.11: 2017 Natural Gas Savings by Sub sector, Northern Service Region – Economic Potential (1000 m^3/yr.)

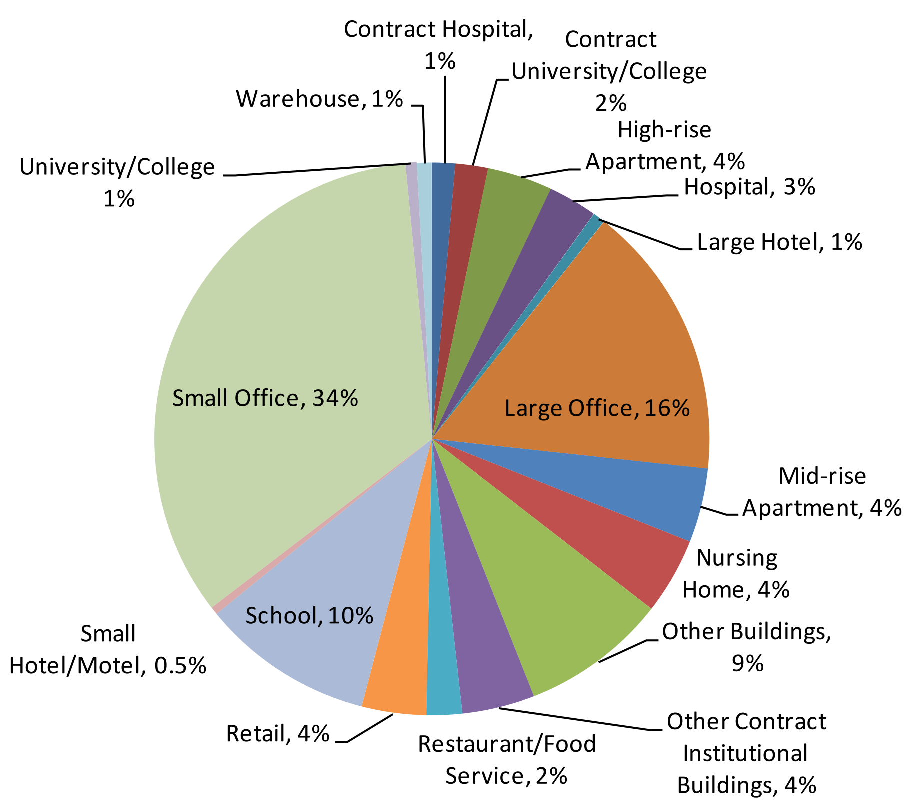


Exhibit 5.12: Natural Gas Savings by Sub Sector and End Use, Southern Service Region, 2017 (1000 m^3/yr.)

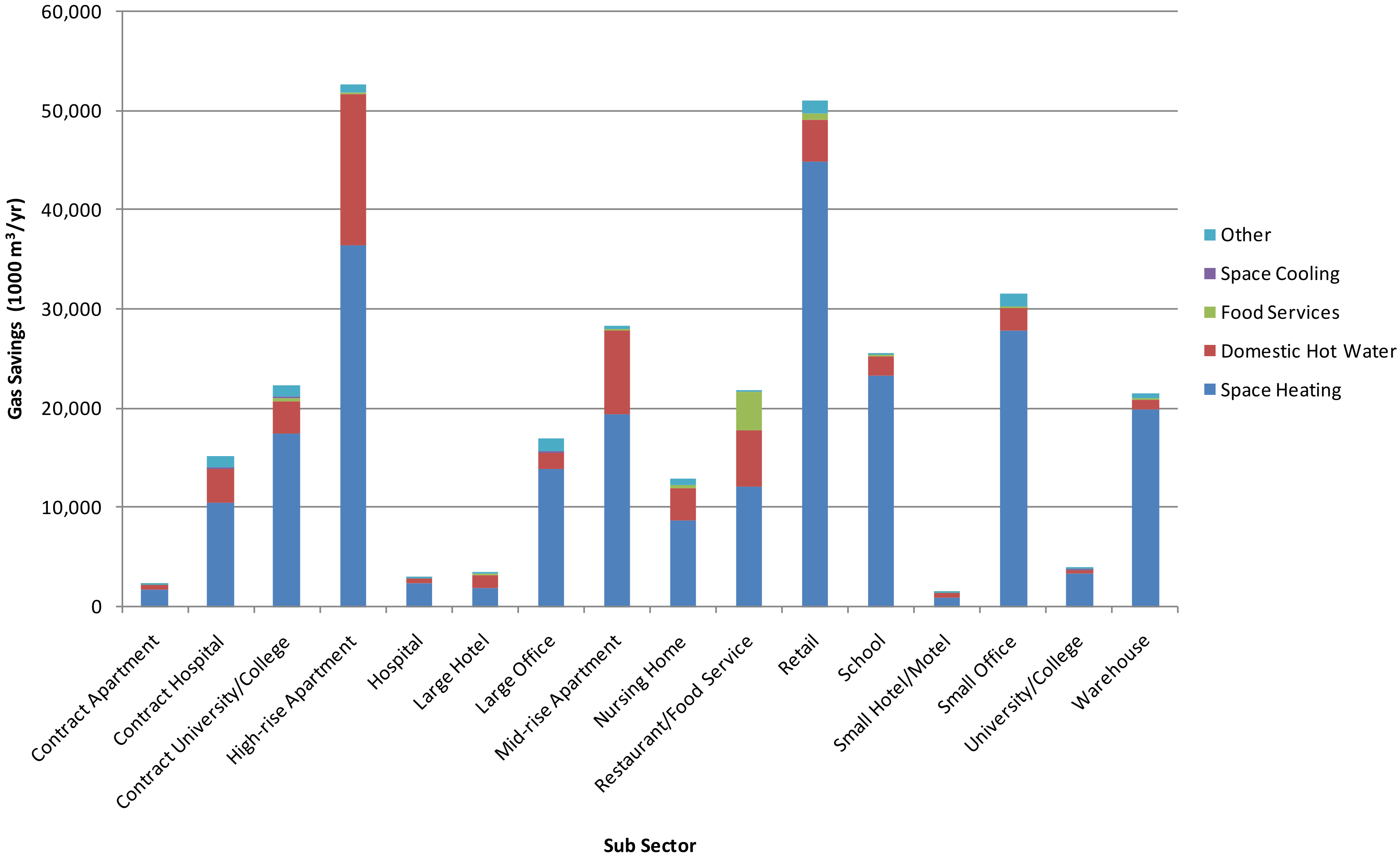


Exhibit 5.13: Natural Gas Savings by Sub Sector and End Use, Northern Service Region, 2017 (1000 m³/yr.)

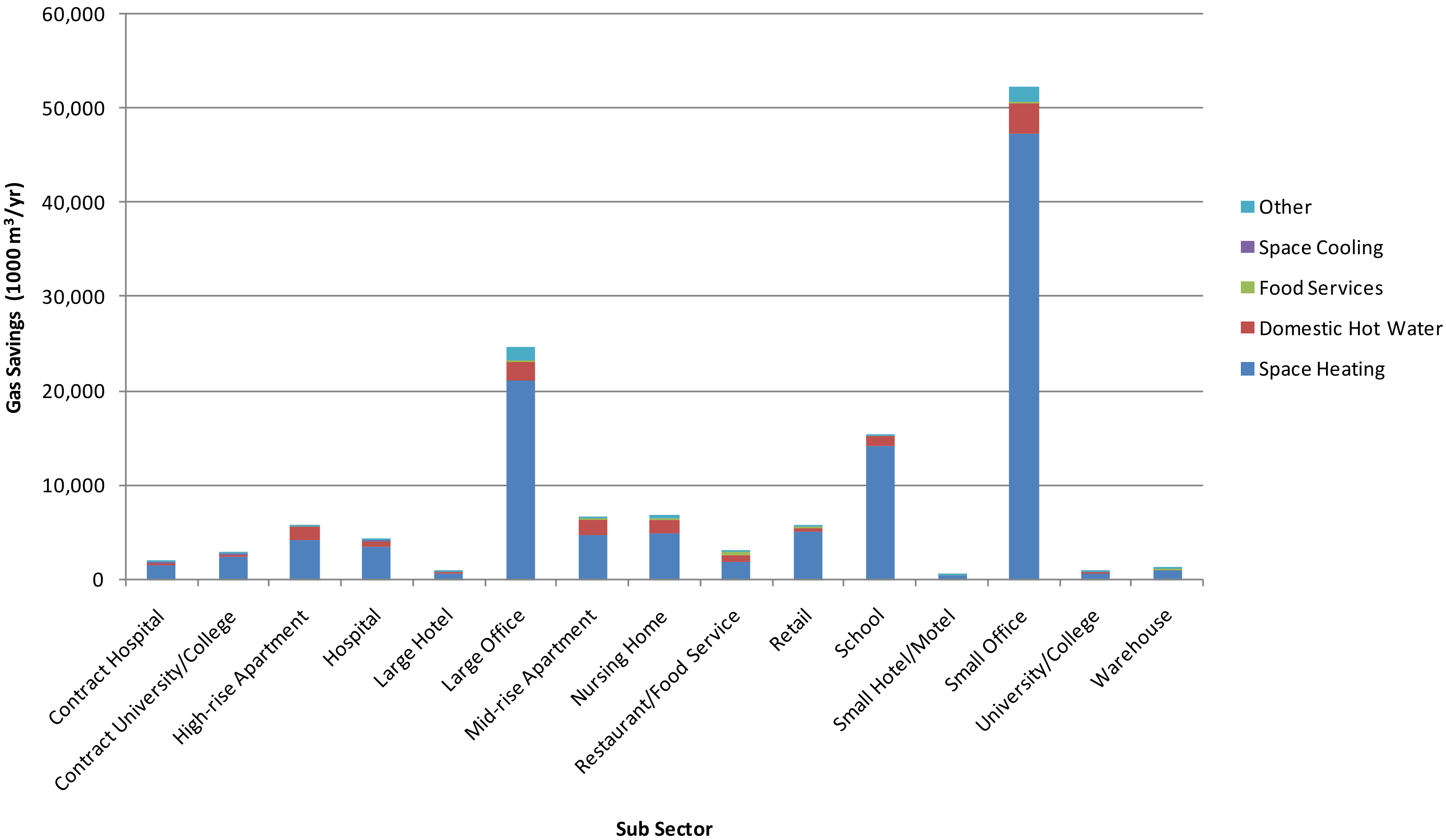


Exhibit 5.14: Natural Gas Savings by Sub Sector and Building Vintage, Southern Service Region, 2017 (1000 m^3/yr.)

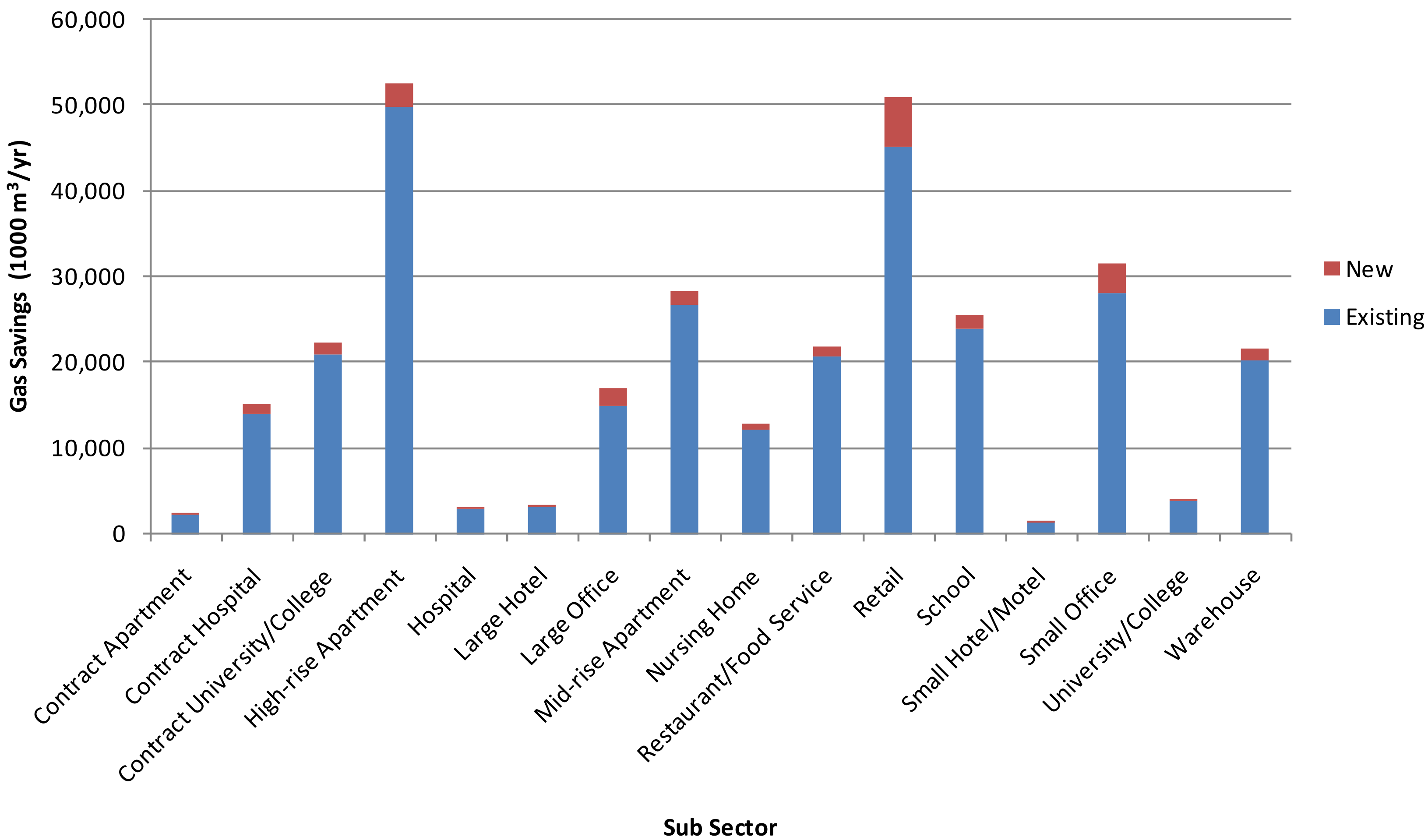
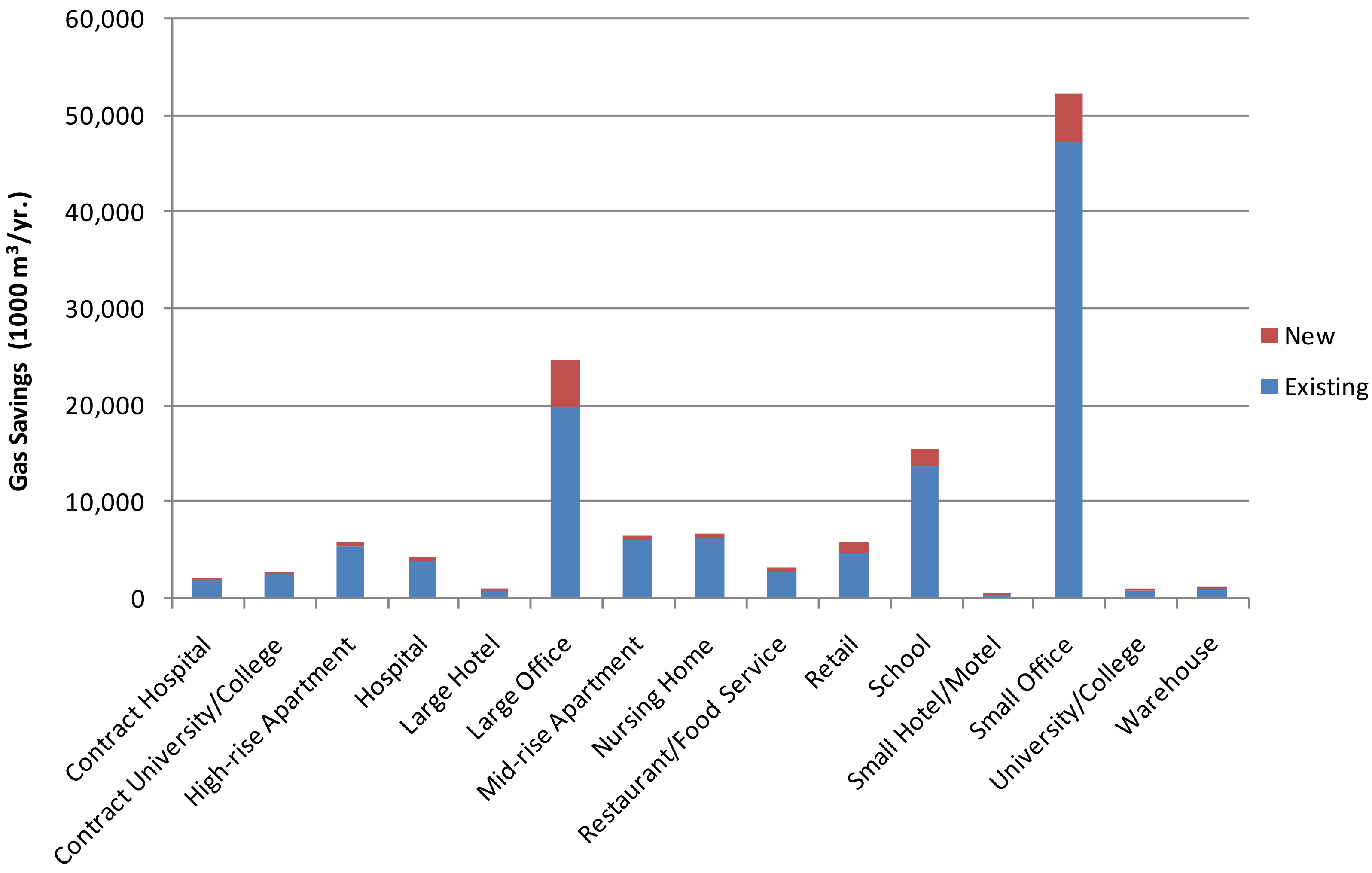


Exhibit 5.15: Natural Gas Savings by Sub Sector and Building Vintage, Northern Service Region, 2017 (1000 m^3/yr.)



5.5 INTERPRETATION OF RESULTS

Highlights of the results presented in the preceding exhibits are summarized below.

Savings by Service Region

The Southern service region represents slightly more than 75% of the identified savings in 2017. This is to be expected given the large number of customers in this service region.

Savings by Milestone Year

Approximately 80% of the identified economic potential savings in 2017 were identified as economically feasible by 2012. This is because a number of measures are cost effective at full cost, i.e., it is economically attractive to implement them before the equipment they affect or replace has reached the end of its useful life. Under the Economic Potential Forecast, they would therefore be implemented right away. The other factor that causes 2012 savings to look relatively large as a proportion of 2017 is the natural conservation expected in the Commercial sector over the course of the study. Savings are calculated based on the expected difference between the Reference Case forecast (which includes savings from natural conservation) and the Economic Potential Forecast. As naturally occurring savings gradually increase, they erode some of the economic potential.

Savings by Sub Sector

Among modelled sub sectors in the Southern service region, High-rise Apartment buildings and Retail buildings have the highest portion of identified savings (approximately 11% each).

In the Northern service region, the Small Office sub sector accounts for nearly 34% of identified savings, followed by Large Office (16%). Other Buildings[169] make up 10%.

Savings by End Use

Space heating measures account for approximately 78% of the total identified energy savings in the Southern service region and 85% in the Northern service region. Water heating measures account for approximately 17% and 11% of savings in the Southern and Northern service region, respectively.

5.5.1 Caveats on Interpretation of Results

A systems approach was used to model the energy impacts of the efficiency upgrades presented in the preceding section. In the absence of a systems approach, there would be double counting of savings and an accurate assessment of the total contribution of the energy-efficient upgrades would not be possible.

[169] Recreational buildings, religious buildings, gas stations, laundromats, and buildings classified as “other commercial”, “other institutional” and “other multifamily” in Union’s customer database.

For example, a condensing boiler reduces space heating natural gas use, as does the installation of new energy-efficient glazings. On its own, each measure will reduce overall space heating energy use. However, the two savings are not additive. The order in which some upgrades are introduced is also important. In this study, the approach has been to select and model the impact of measures that reduce the load for a given end use (e.g., roof insulation or glazing upgrades that reduce the space heating load) and then to introduce measures that meet the remaining load more efficiently (e.g., a high-efficiency space heating system).

The above approach means that where there is interaction between measures that affect the same end use, the savings for those individual measures are reduced. As appropriate, this issue is addressed in the Achievable Potential section of this report.

6. ACHIEVABLE POTENTIAL FORECAST

6.1 INTRODUCTION

This section presents the Commercial sector Achievable Potential natural gas savings for the study period (2007 to 2017). The Achievable Potential is defined as the proportion of the gross savings identified in the Economic Potential Forecast that could realistically be achieved within the study period.

The discussion is organized into the following sub sections:

- Description of Achievable Potential
- Approach to the Estimation of Achievable Potential
- Achievable Potential Workshop Organization
- Achievable Potential Workshop Results
- Achievable Potential DSM Investment Scenario Results
- Summary and Interpretation of Results.

6.2 DESCRIPTION OF ACHIEVABLE POTENTIAL

Achievable Potential recognizes that it is difficult to induce all customers to purchase and install all of the energy-efficiency measures that meet the criteria defined by the Economic Potential Forecast presented in the preceding section.

Exhibit 6.1 presents an illustration of the level of natural gas consumption that is estimated in Achievable Potential scenarios. As illustrated in Exhibit 6.1, reductions in natural gas consumption under Achievable Potential are "banded" by the two forecasts presented in previous sections, namely the Reference Case and the Economic Potential Forecast.

Exhibit 6.1: Illustration of Achievable Potential versus Reference Case and Economic Potential Forecasts

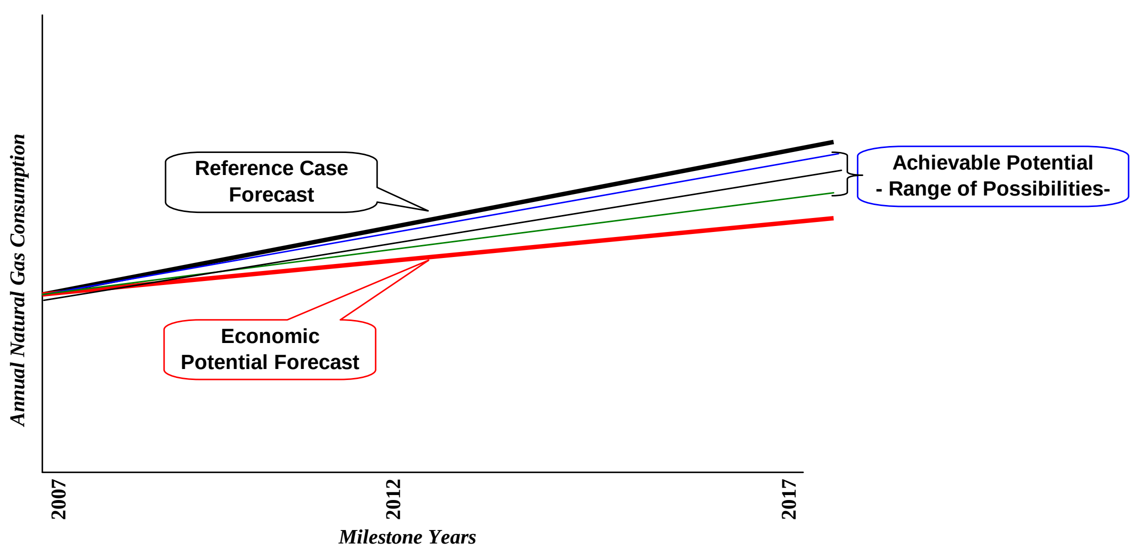


Exhibit 6.1 shows that future natural gas consumption under the Reference Case is greater than in any of the Achievable Potential forecasts. This is because the Reference Case represents a "worst case" situation in which there are no additional utility market interventions and hence no additional natural gas savings beyond those that occur "naturally."

Exhibit 6.1 also shows that future natural gas consumption under the Achievable Potential is greater than in the Economic Potential Forecast. This is because the Economic Potential Forecast assumes that efficient new technologies fully penetrate the market as soon as it is cost effective to do so. However, the Achievable Potential recognizes that under "real world" conditions, the rate at which customers are likely to implement energy-efficiency measures will be influenced by market constraints and, as a result, implementation will occur more slowly than under the assumptions employed in the Economic Potential Forecast. Exhibit 6.2 illustrates some of the types of market constraints that often affect customer implementation of energy-efficiency measures.

Exhibit 6.2: Illustration of "Typical" Market Constraints Affecting Energy-efficiency (EE) Implementation

Category	Barrier
Price Signals	• No monetization of externalities • Tax and subsidies that affect the playing field between EE and the fuels being displaced
Customer EE Awareness	• Awareness that EE opportunities and products exist • Awareness of benefits – cost and co-benefits • Customers' technical ability to assess the options.
Product and Service Availability	• Local or national product availability • Existence of a viable infrastructure of trade allies • Vendor or trade ally awareness of the efficiency options and their understanding of the technical issues
Financing of EE Measures	• Access to appropriate financing • Size of required EE investment vs. asset base • Payback Ratio – Actual vs. Required
Transaction Costs	• Level of effort/hassle required to become informed, select products, choose contractor(s) and install
Perceived Risk/Reward	• Level of perceived risk that the EE product may not perform as promised • Level of positive external/personal recognition for "doing the right thing" by installing the EE measure(s)
Split Incentive/Motivation	• Level to which the incentives of the agent charged with purchasing the EE are aligned with those of the person(s) that would benefit
Regulatory	• Codes or standards that prohibit implementation of innovative EE technologies • Level of EE performance that is required in codes or standards

The Achievable Potential scenarios shown in Exhibit 6.1 are presented as a range. This recognizes not only that any estimate of Achievable Potential over a 10-year period is necessarily subject to uncertainty but also that there are different types and levels of potential DSM program intervention. Government and utility DSM program experience throughout North America has shown that energy-efficiency market barriers can be addressed and customer willingness to accept and purchase energy-efficient products can be positively influenced by a variety of DSM market intervention strategies, such as those noted below in Exhibit 6.3.

The same body of DSM program experience also recognizes that there are limits to the scope of influence of any utility. It recognizes that some markets or sub markets may be so price sensitive or constrained by market barriers beyond the influence of utility DSM programs that they will only fully act if forced to by legal or other legislative means. It also recognizes that there are practical constraints related to the pace that existing inefficient equipment can be replaced by new, more efficient models or that existing building stock can be retrofitted to new energy performance levels. In addition, the design and implementation of DSM market interventions, such as those noted in Exhibit 6.3, require staff and financial resources. In "real world" conditions these resources are also subject to constraints.

Exhibit 6.3: "Illustration" of Potential DSM Market Intervention Strategies[170]

Strategy Type	Description
Alliances	• Vertical integration of market between upstream and downstream market actors (i.e., forming a relationship between contractors and suppliers)
Audit	• An assessment of a building's energy efficiency made by a trained inspector
Contractor Certification	• An assurance that a given contractor is knowledgeable about the product or service, verified through training and/or testing
Demonstration	• Providing demonstration of the use/performance of energy-efficient technologies to market actors
Design Assistance	• Providing recommendations on building or product design
Financing	• Providing loans to finance the acquisition of a product or service
Financial Incentives (and Rebates)	• Per measure dollars provided to market participants (generally either end users or distribution channel members) to encourage energy conservation measure installation
Information	• Passive provision of information to market participants
Linking Vendors & Customers	• Providing customer contacts to contractors, or contractor/vendor contacts to customers
Non-financial Incentives	• Products, changes in procedures or administrative consolidation to encourage product or service provision
Promotion	• Active advertising and information made available to the market
Sales Training	• Providing sales, marketing and/or technical training about products or services to individuals responsible for selling it
Standards, Labelling	• Setting specific standard levels for energy efficient technologies • Labelling these technologies accurately for easy consumer/contractor recognition
Technical Information	• Provision of technical information on energy-efficient products or services
Technical Support	• Providing answer to technical questions from market actors about energy-efficient products/services after installation
Technical Training	• Providing training to trade allies so that they better understand new or existing practices or procedures
Testing Protocols & Standards	• Standardization of testing protocols for installation and repair
Third Party Verification	• Inspection and verification provided by an unbiased party on the results of an inspection to insure correct product or service performance

Source: American Council for an Energy Efficient Economy (ACEEE) Proceedings: 2001.

[170] As in the preceding Exhibit, the strategies shown in Exhibit 6.3 are not necessarily exhaustive; rather, they illustrate the types of options that may be available to DSM program planners.

6.3 APPROACH TO THE ESTIMATION OF ACHIEVABLE POTENTIAL

Consistent with the description outlined above, this study approached the estimation of Achievable Potential by preparing a number of future scenarios, each representing differing assumptions related to the level of DSM program investment over the study period.

In consultation with Union personnel, the study identified two Achievable Potential scenarios to be assessed in this final stage of the study.[171] They are:

- A financially unconstrained DSM investment scenario
- A financially constrained DSM investment scenario based on the maintenance of historic Union DSM program funding levels.

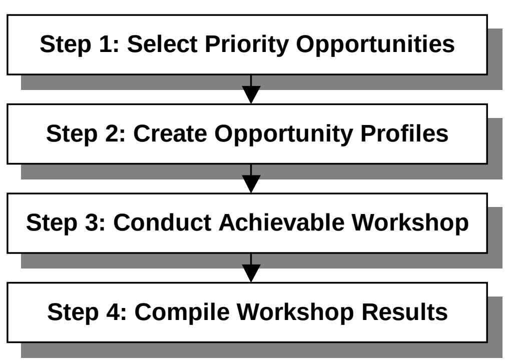
Development of the assumptions employed in each of the above scenarios was based on a combination of Union's own DSM program experience and the results of a one-day workshop involving Union DSM personnel, trade allies and consultant team members.

The workshop results were particularly valuable in generating the DSM investment scenarios; consequently, a brief description of the workshop organization and results is provided in the following sections.

6.4 ACHIEVABLE POTENTIAL WORKSHOP ORGANIZATION

The design and implementation of the Achievable Potential workshop was organized into four steps. A schematic showing the major steps is shown in Exhibit 6.4 and each step is briefly discussed below.

Exhibit 6.4: Approach to Achievable Potential Workshop



[171] It should be emphasized that the estimation of Achievable Potential scenarios is not synonymous with either the setting of specific program targets or with program design. While both are closely linked to the discussion of Achievable Potential, they involve more detailed analysis that is beyond the scope of this study.

Step 1: Select Priority Opportunities

The first step was to review the energy saving opportunities identified in the Economic Potential Forecast and to select a set of those opportunities for discussion in the Achievable Potential workshop. The amount of time available in the workshop for the discussion of energy-efficiency opportunities was limited. Consequently, the number of opportunities selected for discussion was limited to eight, which prior experience had shown to be about the maximum allowable within the available timeframe.

Exhibit 6.5 shows the eight energy-efficiency measures selected. Selection of the opportunities was based on a qualitative application of criteria that were intended to ensure that the workshop discussions would include:

- Technologies and measures that represent a significant share of the potential energy savings identified in the Economic Potential Forecast
- Review of conditions in a variety of sub markets
- Inclusion of new products or markets where little prior DSM experience existed.

Exhibit 6.5: Commercial Sector Opportunity Areas

Opportunity Area	Title	Approximate% of Economic Savings Potential
C1	Roof Insulation	4%
C2	Heat Recovery Ventilators	8%
C3	ENERGY STAR® Fryers	1%
C4	Condensing and Near-Condensing Boilers	5%
C5	Condensing and High-Efficiency Rooftop Units	4%
C6	Recomissioning & Advanced BAS	35%
C7	Condensing Storage Water Heaters	2%
C8	Advanced New Commercial Construction	9%
	Total	68%

Step 2: Create Opportunity Profiles

Brief profiles were prepared for each Opportunity selected in Step 1. The profiles, which were used to introduce the workshop discussion of each Opportunity, provided the following information:

- **Technology description,** e.g., retrofit of existing boilers to condensing models
- **Sub sector and service region,** e.g., existing Large Office Southern service region
- **Selection of a "Typical" application** for discussion purposes

- **Financial and economic indicators for the "Typical" application,** e.g., installed cost, useful life, annual energy savings simple payback, benefit/cost ratio, basis of assessment (incremental versus full cost)

- **Eligible participants** in each milestone period.[172]

Copies of the Opportunity Profile slides are provided in Appendix F.

Step 3: Conduct Achievable Potential Workshop

A one-day Commercial sector Achievable Potential workshop was held on September 25, 2008. Workshop participants consisted of core members of the consultant team, Union DSM personnel and local trade allies. Together, the participants represented a wide range of expertise and experience related to both the DSM technologies and the markets that were discussed during the workshop.

Following a brief consultant presentation that summarized the study result to date, the workshop provided a structured assessment of each of the selected Opportunities. The assessment of each Opportunity began with a brief consultant presentation, as outlined in Step 2 above. The majority of each assessment consisted of a facilitated discussion of the key elements affecting successful promotion and implementation of the DSM Opportunity. More specifically:

- What are the major constraints/challenges constraining customer adoption of the identified energy-efficiency opportunities?
  - How big is the "won't" portion of market for this Opportunity?

- Preferred strategies and potential partners for addressing the identified constraints (high level only)
  - Key criteria that determine customers' willingness to proceed
  - Key potential channel partners
  - Optimum intervention strategies, e.g., push, pull, combination
  - How sensitive is this Opportunity to incentive levels?

Following discussion of market constraints and potential intervention strategies, participants' views on potential participation rates were recorded. The achievable results were recorded as a band of possibilities. To facilitate workshop discussion, two "high level" DSM program scenarios were defined:

- **The Aggressive Marketing scenario,** which assumes both an aggressive program approach and a very supportive context, e.g., healthy economy, very strong public commitment to climate change mitigation, etc. The results of this component of the discussion provided particularly valuable input into the estimation of the Financially Unconstrained Scenario.

[172] For the purposes of the workshop, eligible participants were defined as: total population (e.g., existing Large Office buildings) minus those that have already installed the enegy-efficiency measure (e.g., 10% of building stock) or, due to technical constraints "can't" install the energy-efficient measure (e.g., 5% of building stock).

- **The Static Marketing scenario,** which assumes that market interest and customer commitment to energy-efficiency and sustainable environmental practices remain approximately as current. Similarly, federal, provincial and municipal government energy-efficiency and GHG mitigation efforts remain similar to the present. The results of this component of the discussion provided a valuable second reference point for the estimation of participation rates in the Static Marketing Scenario.

Exhibit 6.6 lists the steps employed in developing the estimated participation rates.

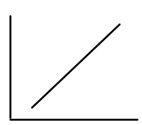
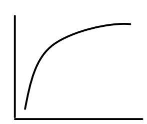
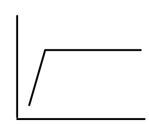
Exhibit 6.6: Workshop Process for Estimating Participation Rates

The participation rate for the Aggressive Marketing scenario in 2017 was estimated.

The shape of the adoption curve was selected for the Aggressive Marketing scenario. Rather than seek consensus on the specific values to be employed in each of the intervening years, workshop participants selected one of four curve shapes that best matched their view of the appropriate “ramp-up” rate for each Opportunity (see below).

This process was repeated for the Static Marketing scenario.

Once participation rates had been established for the specific technology, sub sector and service region selected for the Opportunity discussion, workshop participants provided guidelines to the consultants for extrapolating the discussion results to the other sub sectors and service regions included in the Opportunity, but not discussed in detail during the workshop

Curve A	Curve B	Curve C	Curve D
			

Curve A represents a steady increase in the expected participation rate over the 10-year study period.

Curve B represents a relatively slow participation rate during the first half of the 10-year study period followed by a rapid growth in participation during the second half of the 10-year study period.

Curve C represents a rapid initial participation rate followed by a relatively slow growth in participation during the remainder of the 10-year study period.

Curve D represents a very rapid initial participation rate that results in virtual full saturation of the applicable market during the first milestone period of the 10-year study period.

Step 4: Compile Workshop Results

This step involved aggregating the results of the eight Opportunities discussed during the workshop and extrapolating the results of the remaining Opportunities that were identified in the Economic Potential Forecast but not discussed during the workshop.

6.5 ACHIEVABLE POTENTIAL WORKSHOP RESULTS

The following discussion provides a summary of the workshop results for each of the Commercial sector Opportunities noted previously in Exhibit 6.5. In each case, the following information is provided:

- Brief description of the Opportunity and the specific "typical" application selected for the workshop discussion

- Highlights from the workshop discussions related to:
  - Constraints and challenges
  - Potential strategies and partners
  - Incentive sensitivity

- Summary of the estimated participation rates under the Aggressive and Static Marketing scenarios for the selected sub sector
  - Shape of adoption curve selected by the workshop participants

- Summary of major assumptions employed by the consultants for extrapolating the workshop results to other sub sectors.

6.5.1 C1 – Roof Insulation

❑ **Description**

This measure involves upgrading roof insulation to R-22 at time of re-roofing. Cost is estimated at $\$1/ft^2$ (incremental). The measure has a useful life of 20 years and associated savings of up to 20% of space heating energy (depending on building characteristics). The Small Office sub sector was the subject of detailed discussion for this Opportunity.

❑ **Discussion Highlights**

Constraints & Challenges

- Workshop participants felt that increasing roof insulation at the time of re-roofing is often not done due to lack of knowledge on the part of building owners and that replacing insulation at the same levels is often the default option for both roofing contractors and building owners. Participants also noted that the engineering community sometimes fails to consider energy savings due to increased insulation levels.

- Participants identified the incremental cost of increasing roof insulation as a significant barrier as building owners often evaluate contractor quotations on the basis of first cost. Presentation of costs on a lifetime basis, which would make clear the overall benefit, may have the potential to increase participation rates.

- Participants also felt that the split incentive, present in cases when owners of buildings are not responsible for energy costs, presents a significant barrier because the incremental cost of increasing roof insulation is borne by the owner, but the tenant realizes the benefits. Many participants noted that building owners who are not tenants are not attracted to these types of measures because of higher first costs.

Potential Strategies and Partners

- Participants estimated that up to 80% of roofing jobs for small commercial buildings do not involve an engineer or consultant, with the possible exception of properties owned by major management companies. This would suggest that alliances with roofing contractors may be an appropriate program delivery strategy for small commercial buildings. Involvement (and possibly third-party verification) by Union may lend credibility to contractors making energy savings claims. Several other organizations could play a similar verification role, including Enbridge Gas, Natural Resources Canada, the Ontario Power Authority and the Ontario Association of Architects.

- Possible allies include the Canadian Roofing Contractors Association, leading roofing contractors and engineering associations (such as Consulting Engineers of Ontario and Professional Engineers of Ontario).

Incentive Sensitivity

- Participant felt that program participation would be very sensitive to incentive level and that incentives would need to be well publicized and understood to achieve high participation.

- **Participation Rates – Small Office, Southern Service Region**

Workshop participants concluded that, under the conditions represented by the Aggressive Marketing scenario, participation rates of 80% of eligible customers could be achieved in Small Office buildings in the Southern service region in the year 2017. Workshop participants mentioned adoption curves A and B as the possible best fits with the pace of participation in the intervening years from 2007 to 2017 under the Aggressive Marketing scenario, and ultimately suggested a "flattened" curve B as the most likely adoption curve.

Under the more modest market conditions represented by the Static Marketing scenario, participation rates of 20% could be achieved in Small Office buildings in the Southern service region by 2017. Workshop participants agreed that a "flattened" curve B again represented the best fit with the pace of participation in the intervening years from 2007 to 2017 under this scenario.

- **Participation Rates - Remaining Regions & Sub Sectors**

Workshop participants felt that participation rates would be similar to the above values in all other sub sectors in the Southern service region. It was felt that participation rates in the Northern service region would be slightly higher than those for the Southern service region, based primarily on better paybacks in areas with higher heating demands.

The preceding results were used as a reference point for estimating participation rates related to high-performance glazings in all sub sectors.

6.5.2 C2 – Air-to-Air Heat Recovery

- **Description**

This measure involves installing air-to-air heat recovery equipment to pre-heat make-up air at the time of equipment replacement. Cost is estimated at $2.17/cfm (incremental). The measure has a useful life of 15 years and associated savings of 50% of ventilation air heating energy. The High-rise Apartment sub sector was the subject of detailed discussion for this Opportunity.

- **Discussion Highlights**

Constraints & Challenges

- Workshop participants noted that air-to-air heat recovery is being installed in energy-efficient new buildings but not in all new construction. Some workshop participants associated with the consulting engineering community felt that there were few economical applications for air-to-air heat recovery in existing High-rise Apartment buildings because incompatible intake/exhaust locations are common.

- By contrast, other participants felt that a significant Opportunity exists in several sub sectors, including Restaurants, Schools, University/College, Hospitals and Nursing Homes. A number of niche applications were also suggested, including laboratories and buildings housing swimming pools.

- As an illustration, one participant noted that in his portfolio of approximately 50 Restaurants, about half have been retrofitted with air-to-air heat recovery equipment in the last three years. These installations are realizing average paybacks of less than two years.

- Some participants noted possible regulatory issues, including various municipal building code requirements, especially in Hospitals, Nursing Homes and apartment buildings.

- Even in attractive technical and economical applications, there have often been disincentives, including increased equipment O&M (especially in restaurants, where there can be high grease content in exhaust stream).

- It was suggested that participation rates would be sensitive to both incentive levels and educational activities. Although the measure may be economically attractive in the absence of incentives, education (e.g., case studies and information from utilities and the engineering community) could be used to provide credibility, increase customer awareness and encourage customers to take on projects.

Potential Strategies and Partners

- Participants viewed the conceptual simplicity of the technology as a positive driver for customer participation.

- Education, in the form of case studies and information from utilities and the engineering community, can be used to provide credibility and increase customer awareness.

- Participants suggested that two delivery channels cover most of the market: the consulting engineering community and large mechanical contractors. Other possible trade allies include large HVAC suppliers.

Incentive Sensitivity

- It was suggested that participation rates would be sensitive to both incentive levels and educational activities. Although this measure may be economically attractive in the absence of incentives, educational activities could be used to provide credibility, increase customer awareness and encourage customers to take on projects.

- **Participation Rates – High-rise Apartment, Southern Service Region**

Workshop participants concluded that, under the conditions represented by the Aggressive Marketing scenario, participation by 80% of eligible customers could be achieved in High-rise Apartment buildings in the Southern service region in the year 2017. Workshop participants agreed that adoption curve B represented the best fit with the estimated pace of participation in the intervening years from 2007 to 2017 under this scenario.

Under the Static Marketing scenario, participation rates of 50% could be achieved in this sub sector. Workshop participants again felt that adoption curve B represented the best fit with the pace of participation in the intervening years from 2007 to 2017.

- **Participation Rates - Remaining Regions & Sub Sectors**

Workshop participants felt that participation rates would be similar in other sub sectors in the Southern service region, while all sub sectors in the Northern service region would have directionally higher participation rates due to improved paybacks in areas with higher heating demands.

The preceding results were used as a reference point for estimating participation rates related to demand controlled ventilation and demand controlled kitchen ventilation.

6.5.3 C3 - ENERGY STAR® Fryers

- **Description**

This measure involves upgrading to an ENERGY STAR® fryer at time of equipment replacement. Cost is estimated at $1,100/unit (incremental). The measure has a useful life of 10 years and has associated savings of 30% over a standard fryer. The Restaurant / Food Service sub sector was the subject of detailed discussion for this Opportunity.

- **Discussion Highlights**

Constraints & Challenges

- Participants noted that there is some penetration of this type of technology in larger restaurant chains. In some quick service restaurants, fryers may comprise half of cooking energy use, making this measure especially attractive. Even given this, cooking equipment efficiency is often a low priority, partly due to perceived high transaction costs.

- Participants felt that first cost is especially important for restaurants. In many cases, even a short payback may not be attractive where restaurants are concerned as many restaurants have very short operating lifetimes.

- Although energy costs are becoming a larger share of overall operating costs, participants felt that restaurant management may not have “caught up” and are not fully aware of this situation.

- Some participants felt that the publicly operated buildings sector (i.e., hospitals, nursing homes, and cafeterias in government buildings) would likely find this measure more attractive than the privately run buildings sector.

Potential Strategies and Partners

- Given that this is often not a primary concern to restaurant operators, it was suggested that an appropriate approach might be for Union to reduce transaction costs by handling delivery and installation in a similar manner to the existing pre-rinse spray valve program. The customer would be required to purchase the equipment and provide Union with a list of locations for delivery/installation.

- Equipment suppliers and manufacturers would be key trade allies for this type of scenario; regardless of program type, another important ally would be the large restaurant chains. It was estimated that there is one individual responsible for purchasing for every 80 quick service restaurants in Ontario.

- Participants again felt that Union could lend credibility to a program by way of promotion and that, for restaurants, individual priorities are a more appropriate program strategy than a bundled “energy management” approach.

Incentive Sensitivity

- Participants felt that this Opportunity was incentive sensitive. Given that energy efficiency is not often a primary concern to restaurant operators, an incentive would likely be required to “get the attention” of those making purchasing decisions.

❑ **Participation Rates – Restaurant / Food Service, Southern Service Region**

Workshop participants concluded that under the conditions represented by the Aggressive Marketing scenario, participation of 80% of eligible customers could be achieved in Restaurants in the Southern service region in the year 2017. Workshop participants agreed that adoption curve A represented the best fit with the estimated pace of participation in the intervening years from 2007 to 2017 under this scenario.

Under the Static Marketing scenario, participation rates of 55% could be achieved in this sub sector. Workshop participants again felt that adoption curve A represented the best fit with the pace of participation in the intervening years from 2007 to 2017.

❑ **Participation Rates - Remaining Regions & Sub Sectors**

Workshop participants felt that participation rates would be similar in all other sub sectors in the Southern service region, with the exception of Hospitals, where rates were expected to be higher as a result of government purchasing patterns. Participants felt that Northern service region sub sectors would have similar participation rates to those in the Southern service region.

The preceding results were used as a reference point for estimating participation rates related to high-efficiency broilers and griddles.

6.5.4 C4 – Condensing and Near-Condensing Boilers

❑ **Description**

This Opportunity addressed two technologies. The measure involves upgrading a standard atmospheric boiler to a condensing or near-condensing boiler at the time of equipment replacement. Workshop participants were asked to estimate participation rates for the installation of condensing boilers and were also asked to estimate the portion of customers who did not install condensing boilers but who would instead install near-condensing boilers.

Cost is estimated at $17/MBH and $3/MBH (incremental) for condensing and near-condensing boilers respectively. The measure has a useful life of 25 years and has associated savings of 14% and 6% of space heating energy for condensing and near-condensing boilers, respectively. The Large Office sub sector was the subject of detailed discussion for this Opportunity.

- **Discussion Highlights**

Constraints & Challenges

- Workshop participants discussed several constraints related to condensing boiler technology. These included technical barriers such as the need for low return water temperature (which can be incompatible with some heating loops, especially those employing radiators and baseboards as opposed to fan coils), lower applicability in buildings with constant heating loads (such as multi-unit residential buildings) and added complexity in terms of maintenance for condensing boilers.

- Higher first cost was also cited as a barrier to the financing and uptake of both condensing and near-condensing boilers, even given the attractive payback associated with these technologies.

- Some participants felt that the extra capital cost associated with condensing boilers (as opposed to near-condensing) may not be warranted, as actual savings would be comparable in some configurations.

- Other participants noted that condensing boilers are being installed at present, especially in public buildings.

Potential Strategies and Partners

- Several participants supported custom programs as opposed to prescriptive boiler programs. A custom approach would allow for condensing boilers to be installed where appropriate, and near-condensing boilers where they are more applicable. Some participants felt that prescriptive programs could lead to DSM funds being spent inappropriately, e.g., installing condensing boilers when improving control systems could improve energy efficiency more cost effectively.

- Union personnel suggested that for this Opportunity, the Aggressive Marketing scenario might represent a custom program comparable to the existing Enbridge Gas program in Ontario (in which incentives are based on savings achieved), while the Static Marketing scenario might represent a more prescriptive approach.

- Participants noted that case studies and other technical information would be a useful tool for decision makers. They also suggested that under proper market conditions, entire boiler systems may be replaced, but that low incentives may mean that only single boilers are replaced. Participants from the consulting engineering community estimated that more than half of boiler replacements are presently being completed without engineering work being done.

- Participants felt that the supplier capacity and service support capability needed to expand boiler programming is presently in place.

Incentive Sensitivity

- Workshop attendees agreed that participation in any boiler program would be very incentive sensitive.

❑ **Participation Rates – Large Office, Southern Service Region**

Participants concluded that, for condensing boilers under the Aggressive Marketing scenario, participation by 30% of eligible customers could be achieved in Large Office buildings in the Southern service region in 2017. Of the remaining customers, 60% could upgrade to a near-condensing boiler under this scenario.

Under the Static Marketing scenario, participation by 15% of eligible customers could be achieved for condensing boilers in the same sub sector and timeframe. Of the remaining customers, 50% could upgrade to a near-condensing boiler under this scenario.

For both scenarios, workshop participants agreed that adoption curve A represented the best fit with the estimated pace of participation in the intervening years from 2007 to 2017.

❑ **Participation Rates – Remaining Regions & Sub Sectors**

Workshop participants felt that participation rates would be similar in other sub sectors in the Southern service region, with the exception of Schools, which were expected to have higher participation rates based on the experience of workshop participants. Sub sectors in the Northern service region were expected to have similar participation rates, with improved paybacks in areas with higher heating demands balanced against a slightly less mature market in this region.

The preceding results were used as a reference point for estimating participation rates related to other space heating equipment, including condensing unit heaters and condensing furnaces.

6.5.5 C5 – Condensing and High-efficiency Rooftop Units

❑ **Description**

Similar to Opportunity C4, this Opportunity addressed two technologies. The measure involves upgrading a standard rooftop unit to a condensing or high-efficiency rooftop unit (RTU) at the time of equipment replacement. Workshop participants were asked to estimate participation rates for the installation of condensing RTUs and were also asked to estimate the portion of customers who did not install condensing RTUs but who would instead install high-efficiency RTUs.

Cost is estimated at $25/MBH and $5/MBH (incremental) for condensing and high-efficiency RTUs respectively. The measure has a useful life of 15 years and has associated savings of 19% and 9% of space heating energy for condensing and high-efficiency RTUs respectively. The Retail sub sector was the subject of detailed discussion for this Opportunity.

As condensing rooftop units are at a very early stage of market availability, workshop attendees concluded that participation by 2017 would likely be relatively low and that participation rates would be contingent on a number of difficult to estimate factors (discussed below). Workshop participants decided to discuss this Opportunity but did not estimate rates of participation for condensing rooftop units.

❑ **Discussion Highlights**

Constraints & Challenges

- Some workshop participants felt that, as a product new to the marketplace, condensing rooftop units may have technical issues and that improvements may come slowly because there are only a few small equipment manufacturers involved. It was felt that this technology would, at best, see a very slow increase in market penetration.

- Some participants felt that customers could demand a solution if market conditions warranted, although it was felt that these market conditions do not exist at present. The example of residential condensing furnaces was cited, in which market share in the Union Service Area increased from near zero to a significant portion of homes over the 10-year period between 1980 and 1990.

- To the best of participants' knowledge, only two small manufacturers are developing condensing rooftop units at present. Instead, most manufacturers are focusing on improving cooling efficiencies of packaged rooftop units. This is driven by demand from the U.S. It was also noted that high-efficiency modulating rooftop units are only available from most manufacturers as custom builds for sizes less than 20 tons.

- Participants felt that this technology is likely to be seen in new construction before it is implemented as a retrofit.

- It was noted that in a more mature market scenario, savings from condensing rooftop units would be more widely applicable than for condensing and near-condensing boilers (discussed in Opportunity C4).

Potential Strategies and Partners

- Participants felt that a condensing rooftop unit program would need to focus on market transformation. Potential strategies could include demonstrations and provision of technical information.

Incentive Sensitivity

- Participants felt that a condensing rooftop unit program would need to focus on market transformation, not simply incentives.

As workshop attendees did not estimate participation rates for this Opportunity, participation rates from Opportunity C4 were taken into account when estimating participation for high efficiency rooftop units, while condensing rooftop units were not included in either the Aggressive or Static Marketing scenarios.

6.5.6 C6 – Recommissioning and Advanced BAS

- **Description**

This measure involves applying the retrocommissioning process to an existing building and/or installing an advanced building automation system (BAS). Workshop participants were asked to estimate participation rates for both building recommissioning and the installation of advanced BAS. Cost is estimated at $0.35/ft^{2}and $0.90/ft^2 for recommissioning and advanced BAS respectively. The measures have a useful life of five and 10 years, and associated savings of 15 and 10% of space heating, cooling and "other gas use" for recommissioning and advanced BAS, respectively. The Large Office sub sector was the subject of detailed discussion for this Opportunity.

- **Discussion Highlights**

Constraints & Challenges

- Some workshop participants raised concerns regarding interoperability issues related to advanced BAS and existing BAS due either to the age of the existing system or the proprietary software embodied in existing systems. It was estimated that this might affect up to 50% of the existing stock to some degree.

- Participants noted that a large portion of savings associated with advanced BAS and controls are dependent on operator training and knowledge as well as monitoring and upkeep. Union could play a role in ensuring education is available, emphasizing the importance of maintenance/maintenance agreements, and providing credibility/verification of suppliers' claims.

- With respect to recommissioning, the primary barrier discussed was a lack of qualified service providers, as providers must be knowledgeable about several building systems. The requirement for this broad expertise also has the potential to increase costs.

- Participants noted that jurisdictions that have certification programs are further ahead than Ontario in terms of the availability of service providers and promoting recommissioning. Contractor certification was cited as a potential driver for increased rates of recommissioning.

- Participants suggested that it is difficult to attribute savings due to recommissioning and that interveners and regulators often prefer hard technologies to operational measures or measures requiring evaluation.

Potential Strategies and Partners

- Participants noted that BAS could allow for central monitoring with a dedicated staff for monitoring/maintenance. This often puts decision making into the hands of more qualified individuals at companies that are large enough to provide a dedicated resource.

- It was suggested that Union's role in promoting recommissioning could include identifying and publicizing qualified individuals/firms and providing training opportunities.

- It was noted that another Ontario utility presently has a monitoring and assessment program in place for recommissioning (in which energy consumption is tracked for 12 months and an incentive is provided for savings over the time period). Union personnel suggested that the Aggressive Marketing scenario could involve some type of monitoring and evaluation process to allow for savings verification.

- It was suggested that if a qualified consultant was to make recommendations, an incentive could be provided to those who provide proof that these recommendations have been acted upon.

Incentive Sensitivity

- Participants felt that although advanced BAS and recommissioning provided an attractive payback in the absence of any incentive, participation rates for both would be incentive sensitive.

❑ **Participation Rates – Retail, Southern Service Region**

With respect to advanced BAS, under the Aggressive Marketing scenario, workshop participants estimated that participation by 95% of eligible customers could be achieved in Large Office buildings in the Southern service region in 2017. Under the Static Marketing scenario, participants estimated that participation rates of 75% could be achieved. Curve A was suggested as the most likely pattern of market uptake for both scenarios.

With respect to recommissioning, under the Aggressive Marketing scenario, workshop participants estimated that participation by 75% of eligible customers could be achieved in Large Office buildings in the Southern service region in 2017. Under the Static Marketing scenario, participants estimated that participation rates of 50% could be achieved. Curve A was suggested as the most likely pattern of market uptake for both scenarios.

- **Participation Rates - Remaining Regions & Sub Sectors**

Workshop participants felt that participation rates would be directionally higher in High-rise Apartments in the Southern service region, and lower in several sub sectors, including Small Office, Retail, Small Hotel/Motel, Restaurant and Mid-rise Apartment. It was felt that participation would be similar in the Northern service region.

The preceding results were used as a reference point for estimating participation rates related to other low-cost/short payback measures, including air sealing, steam plant efficiency measures, low-flow faucet aerators, low-flow showerheads and low flow pre-rinse spray valves. These discussions also informed the estimation of participation rates for other measures that may be included in the recommissioning of a building, including air curtains, de-stratification fans and heat reflector panels.

6.5.7 C7 – Condensing Storage Water Heaters

- **Description**

This measure involves upgrading from a standard water heater to a condensing water heater at the time of equipment turnover. Cost is estimated at $13/MBH. The measure has a useful life 15 years and associated savings of 24% of water heating energy. The High-rise Apartment sub sector was the subject of detailed discussion for this Opportunity.

- **Discussion Highlights**

Constraints & Challenges

- Participants noted that while condensing water heaters are presently being installed in some retrofit situations, contractors continue to drive market uptake. As customer awareness of energy-efficient options is often low, in many cases it was felt that the default option is to replace equipment at the end of its service life with a similar technology.

Potential Strategies and Partners

- Mechanical contractors were identified as a key trade allies.
- Equipment availability/supply was not identified an issue although access to maintenance or installation contractors may be a limiting factor in some parts of the Union Service Area.
- Participants felt that an alliance with manufacturers would be beneficial.

Incentive Sensitivity

- Participants felt that both building owners and contractors would need to be incented to achieve high participation rates

- **Participation Rates – High-rise Apartment, Southern Service Region**

Workshop participants concluded that, under the conditions represented by the Aggressive Marketing scenario, participation by 80% of eligible customers could be achieved in High-rise Apartment buildings in the Southern service region in the year 2017. Workshop participants agreed that adoption curve A represented the best fit with the estimated pace of participation in the intervening years from 2007 to 2017 under this scenario.

Under the Static Marketing scenario, participation rates of 40% could be achieved in this sub sector. Workshop participants again felt that adoption curve A represented the best fit with the pace of participation in the intervening years from 2007 to 2017.

- **Participation Rates - Remaining Regions & Sub Sectors**

Workshop participants felt that participation rates would vary among other sub sectors in the Southern service region, with Large Office, Small Office and Retail buildings having directionally lower participation rates, and Large Hotel, Restaurants and University/Colleges having directionally higher participation. It was felt that the Northern service region would have similar participation rates.

The preceding results were used as a reference point for estimating participation rates related to condensing water heaters.

6.5.8 C8 – Advanced New Building Construction

- **Description**

Similar to opportunities C4 and C5, this Opportunity addressed two measures: 1) New buildings – 40% more efficient and 2) New buildings – 25% more efficient. Workshop participants were asked to estimate participation rates for the construction of new buildings 40% more energy efficient than current practice. Participants were also asked to estimate the portion of new buildings not built to the 40% more efficient standard that would instead be built to a 25% more efficient standard.

Cost is estimated at \$4.50/ft^2 and \$2.50/ ft^2 (incremental) for 40% and 25% more efficient construction, respectively. The measure has a useful life of 25 years and has associated savings of 40% and 25% of energy use respectively. The Large Office sub sector was the subject of detailed discussion for this Opportunity.

- **Discussion Highlights**

Constraints & Challenges

- The primary barrier discussed was higher first cost. This was seen as an especially difficult barrier to overcome for buildings that are not owner occupied, creating a split incentive. Perceived risk of under-performing buildings and the difficulty in quantifying savings were also cited as potential barriers.

Potential Strategies and Partners

- Several drivers were noted for various sub sectors. Participants noted that government owned buildings are increasingly being built to LEED standards, which are generally associated with significant energy savings. Other participants noted that schools are generally being designed for high efficiency, but not necessarily LEED accreditation, and that privately built buildings have been less attracted to LEED accreditation. Some participants felt that LEED standards could act as a barrier to the construction of energy-efficient buildings in some cases because the incremental cost of LEED buildings is often increased as a result of non-energy related design aspects.

Incentive Sensitivity

- Union personnel noted that the Ontario Power Authority's High Performance New Construction (HPNC) program is presently providing incentives for energy-efficient new construction. Union's role may be to identify natural gas specific applications and ensure that incentives match those for electric efficiency. Prospective partners for new building programming would be the same as those for HPNC.

- **Participation Rates – Large Office, Southern Service Region**

Participants concluded that for New Buildings – 40% more efficient under the Aggressive Marketing scenario, participation by 20% of eligible buildings could be achieved for Large Office buildings in the Southern service region in 2017. Of the remaining buildings, 80% could be built to a 25% more efficient standard under this scenario.

Under the Static Marketing scenario, workshop participants felt that no additional Large Office buildings would be built to a 40% more efficient standard by 2017; instead, it was estimated that 50% new Large Office buildings would be built to a 25% more efficient standard under this scenario.

For both scenarios, workshop participants agreed that adoption curve B represented the best fit with the estimated pace of participation in the intervening years from 2007 to 2017.

- **Participation Rates - Remaining Regions & Sub Sectors**

Workshop participants felt that participation rates would vary among other sub sectors in the Southern service region, with Small Office, Small Hotel/Motel, Restaurants, Warehouses and Mid-rise Apartment buildings having directionally lower participation rates, and institutional buildings including Hospitals, Schools and Universities/Colleges having directionally higher participation. It was felt that the Northern service region would have similar participation rates.

6.5.9 Extrapolated Participation Rates for Remaining Opportunities

As noted previously, the workshop results were used as a reference point. This knowledge was combined with follow-up discussions with some of the workshop participants and consultant experience to estimate participation rates for the remaining energy-efficiency opportunities contained in the Economic Potential Forecast.

Exhibits 6.7 and 6.14 provide a summary of the estimated participation rates for the Aggressive and Static Marketing scenarios, both for the Opportunities discussed above and for the remaining energy-efficiency opportunities. Each exhibit contains:

- Workshop reference numbers, corresponding to the order of the Opportunities discussed in the workshop
- All of the measures that passed the economic screen and were included in the Economic Potential Forecast
- The participation rates for eligible households by 2017 and the most likely adoption curves to represent participation rates in the intervening years
- Notes that illustrate sources and rationale used by the consultant team when estimating the participation rates shown.

6.6 ACHIEVABLE POTENTIAL RESULTS

Consistent with the description presented earlier in this section, the Achievable Potential results are presented as a range, which is defined by the following two scenarios:

- A Financially Unconstrained scenario, in which potential is limited by market constraints but not by program budget

- A Static Marketing scenario, in which potential is limited by market constraints as well as DSM program budgets that are approximately similar to current Union levels (although the specific programs and technologies addressed would not necessarily be the same).

The results of each scenario are presented below.

6.6.1 Financially Unconstrained DSM Investment Scenario

The financially unconstrained scenario provides an overview of the level of potential natural gas savings that could be achieved if a comprehensive portfolio of DSM programs was launched without any constraint on the availability of program funding. This scenario is based largely on the results of the Aggressive Marketing scenario that was explored during the Achievable Potential workshop.

Although the results of this scenario are not constrained by program funding, the results incorporate consideration of the market constraints identified during the workshop (see Exhibit 6.2), such as product and service availability, customer transaction costs, etc.

This scenario, therefore, provides a high level estimate of the upper level of natural gas savings that could be achieved by Union's commercial customers over the nine-year period beginning in 2009 and ending in 2017. It also provides Union's commercial DSM program personnel with a view of the relative potential contribution of individual sub sectors, end uses, technologies and service regions.

Major Assumptions: Financially Unconstrained Scenario

Major assumptions included within this scenario include:

- All measures that pass the measure TRC screen are included
- No program financial limit is set, except that all measures must continue to pass the measure TRC screen
- Participation rates are constrained by the market barriers noted in the workshop
- Participation rates for measures discussed in the workshop are employed directly and are shown in Exhibit 6.7
- Participation rates for the remaining measures are extrapolated from the workshop results and/or consultant experience and are shown in Exhibit 6.7
- Fixed program costs (e.g., advertising, training workshops, contractor certification, etc.) and incentive costs are included for each measure. The levels selected for the scenario are summarized in Exhibit 6.8. In each case, the values shown draw on the workshop results and recent Union DSM program experience.

Exhibit 6.7: Participation Rates for Financially Unconstrained Scenario

Workshop Reference #	Measure Name	Participation Rate in 2017 *(% of eligible)*	Adoption Curve Shape	Notes
	High-Performance Glazings	80%	A/B	Based on workshop measure C1
C1	Roof Insulation	80%	A/B	Workshop measure C1
	Air Sealing	50%	A	Based on workshop measure C6, consultant experience
	Air Curtains	50%	A	Based on workshop measure C6, consultant experience
C4	Condensing Boilers	30%	A	Workshop measure C4
C4	Near-Condensing Boilers	60%	A	Workshop measure C4
	Condensing Unit Heaters	30%	A	Based on workshop measure C4
C5	High-Efficiency Rooftop Units	60%	A	Based on workshop measure C4
	Steam Plant Efficiency Measures	85%	A	Based on workshop measure C6
	HVLS De-stratification Fans	85%	A	Based on workshop measure C6
	Heat Reflector Panels	85%	A	Based on workshop measure C6
	Demand Controlled Ventilation	80%	B	Based on workshop measure C2
	Demand Control Kitchen Ventilation	80%	B	Based on workshop measure C2
C2	Heat Recovery	80%	B	Workshop measure C2
	Condensing Furnaces	30%	A	Based on workshop measure C4
	Condensing Water Heaters	80%	A	Based on workshop measure C7
C7	Condensing Storage Water Heaters	80%	A	Workshop measure C7
	Low-Flow Faucet Aerators	85%	A	Based on workshop measure C6, consultant experience
	Low-Flow Showerheads	85%	A	Based on workshop measure C6, consultant experience
	Pre-Rinse Spray Valves	85%	A	Based on workshop measure C6, consultant experience
	High-Efficiency Griddles	80%	A	Based on workshop measure C3
	High-Efficiency Broilers	80%	A	Based on workshop measure C3
C3	ENERGY STAR® Fryers	80%	A	Workshop measure C3
C6	Building Recommissioning	75%	A	Workshop measure C6
C6	Advanced Building Automation Systems	95%	A	Workshop measure C6
C8	High-Performance New Construction - 25% more efficient	80%	B	Workshop measure C8
C8	High-Performance New Construction - 40% more efficient	20%	B	Workshop measure C8

Exhibit 6.8: Summary of Program Cost Assumptions – Financially Unconstrained Scenario[173]

Measure Name	Fixed Program Costs ($/yr)	Incentive Amount	Incentive Basis	Payback After Incentive (yrs.)	Notes
High-Performance Glazings	37,500	$0.10	per m^3 saved	5.5	Max. incentive $25K
Roof Insulation	37,500	$0.10	per m^3 saved	7.4	Max. incentive $25K
Air Sealing	5,000	$750	per unit	3.3	
Air Curtains	12,000	$1,000	per unit	0.7	
Condensing Boiler - Baseline: Standard Boiler	10,000	$3,000	per unit	4.4	
Condensing Boiler - Baseline: Near-condensing	10,000	$3,000	per unit	6.4	
Near-Condensing Boiler - Baseline: Standard Boiler	10,000	$2,941	per unit	0.0	Capped at 100% of incremental cost
Condensing Unit heater	10,000	$2,000	per unit	1.3	
High-Efficiency Rooftop Unit - Baseline: Standard Efficiency	10,000	$1,000	per unit	1.0	
Condensing Rooftop Unit - Baseline: Standard Efficiency	10,000	$2,159	per unit	4.0	Assume same incentive/ m^3 as HE rooftops
Steam Plant Efficiency Measures	12,000	65%	% of cost	0.4	Max. incentive $12K
HVLS De-stratification Fans	12,000	$1,200	per unit	2.7	
Heat Reflector Panels	15,000	100%	% of installed cost	0.0	
Demand Controlled Ventilation	15,000	$1,800	per unit	1.2	
Demand Control Kitchen Ventilation	25,000	$1,800	per unit	1.3	
Heat Recovery	15,000	$500	per unit	2.4	
Condensing Furnace	10,000	$600	per unit	0.0	Capped at 100% of incremental cost
Condensing Water Heater - Baseline: Standard Efficiency	12,000	$750	per unit	2.9	
Condensing Storage Water Heater - Baseline: Standard Efficiency	12,000	$750	per unit	2.1	
Low-Flow Faucet Aerators - 3 min/day	12,500	100%	% of installed cost	0.0	
Low-Flow Showerheads - 10 min/day	12,500	100%	% of installed cost	0.0	
Pre-Rinse Spray Valve - 40 min/day	25,000	100%	% of installed cost	0.0	
Commercial Cooking - High-Efficiency Griddle	10,000	$1,000	per unit	0.7	
Commercial Cooking - High-Efficiency Broiler	10,000	$200	per unit	0.0	Capped at 100% of incremental cost
Commercial Cooking - ENERGY STAR® Fryer	10,000	$1,000	per unit	0.4	
Building Recommissioning	25,000	$0.10	per m^3 saved	0.8	
Advanced Building Automation Systems	25,000	$0.10	per m^3 saved	3.4	
High-Performance New Construction - 25% More Efficient	30,000	$0.10	per m^3 saved	4.6	
High-Performance New Construction - 40% More Efficient	30,000	$0.10	per m^3 saved	4.7	

[173] Fixed program costs and incentive levels were provided by Union based on workshop results and current experience.

Results: Financially Unconstrained Scenario

Under the conditions defined by this scenario, total Commercial sector natural gas savings in 2017 are estimated to be approximately 390 million m^3/yr. This represents a saving of approximately 18%, relative to the Reference Case, and is equal to approximately 62% of the savings identified in the Economic Potential Forecast. Further detail is provided in the following exhibits:

- Exhibit 6.9 shows total natural gas savings by service region and milestone year
- Exhibit 6.10 shows total natural gas savings by sub sector end use and milestone year for the total Union Service Area
- Exhibit 6.11 shows total natural gas savings by sub sector, end use and milestone year for the Southern service region
- Exhibit 6.12 shows total natural gas savings by sub sector, end use and milestone year for the Northern service region
- Exhibit 6.13 shows annual natural gas savings for the year 2017 by measure bundle, together with the estimated program costs and TRC benefits for the total Union Service Area. (**Note**: the values shown in Exhibit 6.13 are for the single year 2017 only; consequently, they do not add to the same values shown in the preceding exhibits),

Exhibit 6.9: Natural Gas Savings by Service Region and Milestone Year, Financially Unconstrained Scenario (1000 m^3/yr.)

Milestone Year	Southern Region	Northern Region	Total	% Savings Relative to Ref Case
	(1000 m^3/year)			
2012	130,457	41,873	172,330	8%
2017	293,429	96,647	390,076	18%
% Savings 2017 Re: Reference Case	18%	19%	18%	
% Savings 2017 Re: Total	75%	25%	100%	

Exhibit 6.10: Natural Gas Savings by End use and Milestone Year, Total Union Service Area – Financially Unconstrained Scenario (1000 m^3/yr.)

Sub Sector	Milestone Year	Total	Space Heating	Water Heating	Cooking	Space Cooling	Other
Large Office	2012	12,360	10,438	1,112	5	11	793
	2017	27,806	23,671	2,371	24	22	1,718
Small Office	2012	21,141	18,950	1,421	10	0	760
	2017	49,949	45,065	3,204	42	0	1,638
Retail	2012	13,298	11,651	1,250	65	0	331
	2017	31,154	27,456	2,684	277	0	737
Large Hotel	2012	1,359	642	646	10	0	61
	2017	2,995	1,506	1,319	40	0	130
Small Hotel/Motel	2012	618	350	232	1	0	35
	2017	1,392	820	494	4	0	74
Contract Hospital	2012	5,686	3,776	1,431	17	19	443
	2017	12,076	8,206	2,863	71	38	899
Hospital	2012	2,344	1,748	496	8	5	88
	2017	5,113	3,894	995	32	10	182
Nursing Home	2012	5,445	3,416	1,721	42	0	266
	2017	12,270	8,027	3,508	174	0	561
School	2012	13,096	11,977	1,036	27	0	56
	2017	29,197	26,805	2,162	111	0	119
Contract University/College	2012	7,623	5,746	1,342	42	38	455
	2017	16,689	12,827	2,687	172	75	928
University/College	2012	1,522	1,212	242	7	7	54
	2017	3,344	2,705	486	27	14	111
Restaurant/Food Service	2012	6,433	4,003	2,026	384	0	20
	2017	15,375	9,454	4,302	1,577	0	42
Warehouse	2012	6,836	6,319	332	2	0	183
	2017	14,782	13,652	734	8	0	388
Contract Apartment	2012	790	494	282	0	0	13
	2017	1,716	1,105	583	1	0	27
High-rise Apartment	2012	18,379	11,831	6,237	8	0	303
	2017	40,022	26,466	12,883	32	0	640
Mid-rise Apartment	2012	7,054	5,857	1,116	7	0	73
	2017	16,519	13,420	2,913	30	0	156
Other Buildings	2012	26,818					
	2017	60,386					
Other Contract Institutional Buildings	2012	21,530					
	2017	49,291					
Total	2012	172,330	98,412	20,922	635	79	3,934
	2017	390,076	225,078	44,190	2,622	159	8,350

Exhibit 6.11: Natural Gas Savings by End use and Milestone Year, Southern Service Region – Financially Unconstrained Scenario (1000 m^3/yr.)

Sub Sector	Milestone Year	Total	Space Heating	Water Heating	Cooking	Space Cooling	Other
Large Office	2012	5,202	4,281	523	2	11	384
	2017	11,511	9,550	1,106	11	22	822
Small Office	2012	7,806	6,886	597	4	0	320
	2017	18,428	16,371	1,348	18	0	691
Retail	2012	11,983	10,473	1,147	60	0	303
	2017	28,006	24,620	2,461	253	0	672
Large Hotel	2012	1,045	477	512	8	0	48
	2017	2,294	1,115	1,045	31	0	103
Small Hotel/Motel	2012	441	234	179	1	0	27
	2017	988	547	380	3	0	57
Contract Hospital	2012	5,020	3,302	1,287	15	18	398
	2017	10,640	7,160	2,573	63	37	807
Hospital	2012	987	705	234	3	4	41
	2017	2,130	1,557	468	13	8	85
Nursing Home	2012	3,595	2,187	1,195	29	0	184
	2017	8,045	5,106	2,434	120	0	385
School	2012	8,218	7,462	701	18	0	38
	2017	18,206	16,593	1,459	75	0	80
Contract University/College	2012	6,755	5,053	1,215	38	37	412
	2017	14,758	11,257	2,433	156	73	840
University/College	2012	1,225	965	203	6	7	45
	2017	2,682	2,146	406	22	14	93
Restaurant/Food Service	2012	5,596	3,429	1,807	342	0	17
	2017	13,362	8,085	3,836	1,403	0	37
Warehouse	2012	6,443	5,947	319	2	0	175
	2017	13,921	12,838	704	8	0	371
Contract Apartment	2012	790	494	282	0	0	13
	2017	1,716	1,105	583	1	0	27
High-rise Apartment	2012	16,591	10,590	5,716	7	0	278
	2017	36,070	23,652	11,803	29	0	586
Mid-rise Apartment	2012	5,695	4,698	930	6	0	61
	2017	13,313	10,734	2,424	25	0	130
Other Buildings	2012	23,249					
	2017	52,160					
Other Contract Institutional Buildings	2012	19,814					
	2017	45,200					
Total	2012	130,457	67,183	16,847	542	77	2,744
	2017	293,429	152,434	35,464	2,233	155	5,784

Exhibit 6.12: Natural Gas Savings by End use and Milestone Year, Northern Service Region – Financially Unconstrained Scenario (1000 m^3/yr.)

Sub Sector	Milestone Year	Total	Space Heating	Water Heating	Cooking	Space Cooling	Other
Large Office	2012	7,158	6,158	589	3	0	409
	2017	16,294	14,121	1,264	13	0	896
Small Office	2012	13,335	12,064	824	6	0	441
	2017	31,521	28,694	1,856	24	0	947
Retail	2012	1,315	1,178	103	5	0	28
	2017	3,148	2,836	224	24	0	64
Large Hotel	2012	313	165	134	2	0	13
	2017	701	391	274	8	0	28
Small Hotel/Motel	2012	177	116	53	0	0	8
	2017	404	272	114	1	0	17
Contract Hospital	2012	665	474	144	2	0	45
	2017	1,436	1,046	290	7	1	92
Hospital	2012	1,356	1,042	262	4	1	47
	2017	2,983	2,337	528	18	2	98
Nursing Home	2012	1,850	1,230	525	13	0	82
	2017	4,226	2,921	1,074	54	0	176
School	2012	4,877	4,515	335	9	0	18
	2017	10,992	10,212	703	37	0	39
Contract University/College	2012	868	693	127	4	1	43
	2017	1,931	1,570	254	17	1	88
University/College	2012	297	247	40	1	0	9
	2017	663	559	80	4	1	19
Restaurant/Food Service	2012	836	574	218	42	0	2
	2017	2,013	1,369	466	174	0	5
Warehouse	2012	394	372	14	0	0	8
	2017	861	814	30	0	0	16
High-rise Apartment	2012	1,788	1,241	521	1	0	26
	2017	3,952	2,814	1,080	3	0	55
Mid-rise Apartment	2012	1,358	1,159	186	1	0	12
	2017	3,206	2,685	489	5	0	27
Other Buildings	2012	3,569					
	2017	8,226					
Other Contract Institutional Buildings	2012	1,716					
	2017	4,091					
Total	2012	41,873	31,229	4,075	93	2	1,189
	2017	96,647	72,644	8,726	390	5	2,566

Exhibit 6.13: Annual Natural Gas Savings and Estimated Program Costs by Major Measure Type for One Year of Program Activity (2017) - Total Union Service Area, Financially Unconstrained Scenario

Measure Bundle	Financially Unconstrained Potential 2017		Program Costs, 2017 (1000 $)	Program Costs per Unit	
	Gas Savings (1000 m^3/yr.)	TRC Benefits (1000 $)		per Natural Gas Savings ($/$m^3$)	per TRC Benefits ($/$)
Efficient Food Service Equipment	365	511	408	$1.12	$0.80
Space Heating - Envelope measures (Conductive)	3,928	5,504	468	$0.12	$0.08
Space Heating - Envelope measures - Air Sealing	2,444	3,019	567	$0.23	$0.19
Space Heating / Other - Recommissioning	18,833	68,725	2,405	$0.13	$0.03
Space Heating - Ventilation Measures - Heat Recovery	9,306	20,342	6,916	$0.74	$0.34
Space Heating - Equipment	2,010	4,576	954	$0.47	$0.21
DHW - Conservation Measures	5,094	22,422	1,449	$0.28	$0.06
DHW - Equipment Measures	892	1,745	520	$0.58	$0.30
New construction - 40% Better	3,368	26,981	367	$0.11	$0.01
Weighted Average				$0.30	$0.09

6.6.2 Static Marketing Scenario

The Static Marketing scenario is based largely on the results of the scenario explored during the Achievable Potential workshop. Consequently, it incorporates consideration of both market constraints and DSM program budget limitations, which are roughly consistent with current Union levels.

This scenario, therefore, provides a high level estimate of the level of natural gas savings that could be achieved by Union's commercial customers over the nine-year period beginning in 2009 and ending in 2017, assuming present levels of program activity and a somewhat different mix of programs. It also provides Union's commercial DSM program personnel with a view of the relative potential contribution of individual sub sectors, end uses, technologies and service regions.

Major Assumptions: Static Marketing Scenario

Major assumptions included within this scenario include:

- All measures that pass the measure TRC screen are included
- No program financial limit is set, except that all measures must continue to pass the measure TRC screen
- Participation rates are constrained by the market barriers noted in the workshop
- Participation rates for measures discussed in the workshop are employed directly and are shown in Exhibit 6.14
- Participation rates for the remaining measures are extrapolated from the workshop results and/or consultant experience and are shown in Exhibit 6.14.
- Fixed program costs (e.g., advertising, training workshops, contractor certification, etc.) and incentive costs are included for each measure. The levels selected for the scenario are summarized in Exhibit 6.15. In each case, the values shown draw on the workshop results and recent Union DSM program experience.

Exhibit 6.14: Participation Rates for Static Marketing Scenario

Workshop Reference #	Measure Name	Participation Rate in 2017 *(% of eligible)*	Adoption Curve Shape	Notes
	High-Performance Glazings	20%	A/B	Based on workshop measure C1
C1	Roof Insulation	20%	A/B	Workshop measure C1
	Air Sealing	35%	A	Based on workshop measure C6, consultant experience
	Air Curtains	35%	A	Based on workshop measure C6, consultant experience
C4	Condensing Boilers	15%	A	Workshop measure C4
C4	Near-Condensing Boilers	50%	A	Workshop measure C4
	Condensing Unit Heaters	15%	A	Based on workshop measure C4
C5	High-Efficiency Rooftop Units	50%	A	Based on workshop measure C4
	Steam Plant Efficiency Measures	63%	A	Based on workshop measure C6
	HVLS De-stratification Fans	63%	A	Based on workshop measure C6
	Heat Reflector Panels	63%	A	Based on workshop measure C6
	Demand Controlled Ventilation	50%	B	Based on workshop measure C2
	Demand Control Kitchen Ventilation	50%	B	Based on workshop measure C2
C2	Heat Recovery	50%	B	Workshop measure C2
	Condensing Furnaces	15%	A	Based on workshop measure C4
	Condensing Water Heaters	40%	A	Based on workshop measure C7
C7	Condensing Storage Water Heaters	40%	A	Workshop measure C7
	Low-Flow Faucet Aerators	63%	A	Based on workshop measure C6, consultant experience
	Low-Flow Showerheads	63%	A	Based on workshop measure C6, consultant experience
	Pre-Rinse Spray Valves	63%	A	Based on workshop measure C6, consultant experience
	High-Efficiency Griddles	55%	A	Based on workshop measure C3
	High-Efficiency Broilers	55%	A	Based on workshop measure C3
C3	ENERGY STAR® Fryer	55%	A	Workshop measure C3
C6	Building Recommissioning	50%	A	Workshop measure C6
C6	Advanced Building Automation Systems	75%	A	Workshop measure C6
C8	High-Performance New Construction - 25% more efficient	50%	B	Workshop measure C8
C8	High-Performance New Construction - 40% more efficient	0%	B	Workshop measure C8

Exhibit 6.15: Summary of Program Cost Assumptions – Static Marketing Scenario[174]

Measure Name	Fixed Program Costs ($/yr)	Incentive Amount	Incentive Basis	Payback After Incentive (yrs.)	Notes
High-Performance Glazings	25,000	$0.05	per m^3 saved	5.6	Max. incentive $15K
Roof Insulation	25,000	$0.05	per m^3 saved	7.5	Max. incentive $15K
Air Sealing	3,000	$500	per unit	3.4	
Air Curtains	7,500	$750	per unit	0.8	
Condensing Boiler - Baseline: Standard Boiler	7,500	$2,000	per unit	4.7	
Condensing Boiler - Baseline: Near-condensing	7,500	$2,000	per unit	7.0	
Near-Condensing Boiler - Baseline: Standard Boiler	7,500	$2,000	per unit	0.6	
Condensing Unit heater	7,500	$1,500	per unit	1.7	
High-Efficiency Rooftop Unit - Baseline: Standard Efficiency	7,500	$500	per unit	1.6	
Condensing Rooftop Unit - Baseline: Standard Efficiency	7,500	$1,079	per unit	4.6	Assume same incentive/ m^3 as HE rooftops
Steam Plant Efficiency Measures	8,000	50%	% of cost	0.6	Max. incentive $6K
HVLS De-stratification Fans	8,000	$1,000	per unit	2.7	
Heat Reflector Panels	10,000	100%	% of installed cost	0.0	
Demand Controlled Ventilation	8,000	$1,500	per unit	1.3	
Demand Control Kitchen Ventilation	15,000	$1,500	per unit	1.4	
Heat Recovery	8,000	$250	per unit	2.9	
Condensing Furnace	7,500	$600	per unit	0.0	Capped at 100% of incremental cost
Condensing Water Heater - Baseline: Standard Efficiency	8,000	$500	per unit	3.3	
Condensing Storage Water Heater - Baseline: Standard Efficiency	8,000	$500	per unit	2.5	
Low-Flow Faucet Aerators - 3 min/day	10,000	100%	% of installed cost	0.0	
Low-Flow Showerheads - 10 min/day	10,000	100%	% of installed cost	0.0	
Pre-Rinse Spray Valve - 40 min/day	20,000	100%	% of installed cost	0.0	
Commercial Cooking - High-Efficiency Griddle	5,000	$500	per unit	3.1	
Commercial Cooking - High-Efficiency Broiler	5,000	$200	per unit	0.0	Capped at 100% of incremental cost
Commercial Cooking - ENERGY STAR® Fryer	5,000	$500	per unit	2.2	
Building Recommissioning	15,000	$0.05	per m^3 saved	0.9	
Advanced Building Automation Systems	15,000	$0.05	per m^3 saved	3.4	
High-Performance New Construction - 25% More Efficient	20,000	$0.05	per m^3 saved	4.6	
High-Performance New Construction - 40% More Efficient	20,000	$0.05	per m^3 saved	4.8	

174 Fixed program costs and incentive levels were provided by Union, based on workshop results and current experience.

Results: Static Marketing Scenario

Under the conditions defined by this scenario, total Commercial sector natural gas savings in 2017 are estimated to be approximately 259 million m^3/yr. This represents a saving of approximately 12%, relative to the Reference Case, and is equal to approximately 42% of the savings identified in the Economic Potential Forecast. Further detail is provided in the following exhibits:

- Exhibit 6.16 shows total natural gas savings by service region and milestone year
- Exhibit 6.17 shows total natural gas savings by sub sector, end use and milestone year for the total Union Service Area
- Exhibit 6.18 shows total natural gas savings by sub sector, end use and milestone year for the Southern service region.
- Exhibit 6.19 shows total natural gas savings by sub sector, end use and milestone year for the Northern service region.
- Exhibit 6.20 shows annual natural gas savings for the year 2017 by measure bundle, together with the estimated program costs and TRC benefits for the total Union Service Area. (**Note**: the values shown in Exhibit 6.20 are for the single year 2017 only; consequently, they do not add to the same values shown in the preceding exhibits).

Exhibit 6.16: Natural Gas Savings by Service Region and Milestone Year, Static Marketing Scenario (1000 m^3/yr.)

Milestone Year	Southern Region	Northern Region	Total	% Savings Relative to Ref Case
	(1000 m^3/yr.)			
2012	85,860	26,749	112,609	5%
2017	195,892	63,310	259,202	12%
% Savings 2017 Re: Reference Case	12%	13%	12%	
% Savings 2017 Re: Total	76%	24%	100%	

Exhibit 6.17: Natural Gas Savings by End use and Milestone Year, Total Union Service Area – Static Marketing Scenario (1000 m^3/yr.)

Sub Sector	Milestone Year	Total	Space Heating	Water Heating	Cooking	Space Cooling	Other
Large Office	2012	7,654	6,288	794	4	8	560
	2017	18,156	15,146	1,737	17	17	1,240
Small Office	2012	13,124	11,583	992	7	0	542
	2017	31,680	28,199	2,253	29	0	1,199
Retail	2012	8,398	7,237	885	46	0	231
	2017	19,194	16,540	1,938	194	0	522
Large Hotel	2012	924	412	461	7	0	44
	2017	2,058	971	963	28	0	96
Small Hotel/Motel	2012	417	227	164	1	0	25
	2017	926	514	354	3	0	56
Contract Hospital	2012	3,939	2,570	1,028	12	13	316
	2017	8,494	5,650	2,110	49	27	657
Hospital	2012	1,605	1,178	357	5	3	62
	2017	3,542	2,648	735	22	7	130
Nursing Home	2012	3,675	2,227	1,226	30	0	192
	2017	8,353	5,259	2,556	122	0	417
School	2012	8,301	7,506	736	19	0	40
	2017	19,554	17,820	1,570	78	0	86
Contract University/College	2012	5,166	3,820	962	30	27	327
	2017	11,444	8,605	1,974	121	55	688
University/College	2012	1,028	806	174	5	5	39
	2017	2,284	1,816	357	19	11	82
Restaurant/Food Service	2012	4,134	2,430	1,421	269	0	14
	2017	10,465	6,275	3,055	1,104	0	31
Warehouse	2012	4,493	4,129	231	1	0	132
	2017	9,907	9,099	512	6	0	290
Contract Apartment	2012	534	324	200	0	0	9
	2017	1,174	731	421	1	0	20
High-rise Apartment	2012	12,396	7,754	4,419	5	0	218
	2017	27,309	17,502	9,311	22	0	473
Mid-rise Apartment	2012	5,105	3,891	1,156	5	0	52
	2017	11,597	8,791	2,670	21	0	115
Other Buildings	2012	17,581					
	2017	40,210					
Other Contract Institutional Buildings	2012	14,136					
	2017	32,855					
Total	2012	112,609	62,381	15,205	445	57	2,803
	2017	259,202	145,566	32,515	1,836	116	6,103

Exhibit 6.18: Natural Gas Savings by End use and Milestone Year, Southern Service Region – Static Marketing Scenario (1000 m^3/yr.)

Sub Sector	Milestone Year	Total	Space Heating	Water Heating	Cooking	Space Cooling	Other
Large Office	2012	3,271	2,614	372	2	8	274
	2017	7,638	6,205	806	8	17	603
Small Office	2012	4,862	4,215	417	3	0	227
	2017	11,698	10,231	950	13	0	505
Retail	2012	7,582	6,517	812	42	0	212
	2017	17,297	14,866	1,775	177	0	479
Large Hotel	2012	713	307	365	5	0	35
	2017	1,582	721	763	22	0	76
Small Hotel/Motel	2012	298	152	126	0	0	20
	2017	661	344	272	2	0	43
Contract Hospital	2012	3,482	2,250	924	11	13	284
	2017	7,496	4,939	1,896	44	27	591
Hospital	2012	680	478	168	2	3	29
	2017	1,487	1,066	345	9	6	61
Nursing Home	2012	2,437	1,431	852	21	0	133
	2017	5,505	3,361	1,771	84	0	288
School	2012	5,242	4,705	497	13	0	27
	2017	12,265	11,098	1,057	52	0	58
Contract University/College	2012	4,585	3,364	871	27	27	297
	2017	10,137	7,564	1,787	109	54	623
University/College	2012	829	643	145	4	5	32
	2017	1,837	1,444	298	16	10	68
Restaurant/Food Service	2012	3,606	2,086	1,267	240	0	13
	2017	9,108	5,375	2,723	982	0	28
Warehouse	2012	4,236	3,887	221	1	0	127
	2017	9,336	8,562	491	6	0	278
Contract Apartment	2012	534	324	200	0	0	9
	2017	1,174	731	421	1	0	20
High-rise Apartment	2012	11,201	6,947	4,049	5	0	199
	2017	24,643	15,660	8,528	21	0	434
Mid-rise Apartment	2012	3,960	3,127	785	4	0	44
	2017	9,031	7,051	1,867	17	0	96
Other Buildings	2012	15,301					
	2017	34,822					
Other Contract Institutional Buildings	2012	13,041					
	2017	30,175					
Total	2012	85,860	43,049	12,072	380	55	1,962
	2017	195,892	99,217	25,750	1,563	113	4,252

Exhibit 6.19: Natural Gas Savings by End use and Milestone Year, Northern Service Region – Static Marketing Scenario (1000 m^3/yr.)

Sub Sector	Milestone Year	Total	Space Heating	Water Heating	Cooking	Space Cooling	Other
Large Office	2012	4,383	3,674	422	2	0	286
	2017	10,518	8,942	931	9	0	637
Small Office	2012	8,262	7,369	575	4	0	315
	2017	19,982	17,968	1,303	17	0	694
Retail	2012	816	720	73	4	0	19
	2017	1,897	1,674	163	17	0	44
Large Hotel	2012	211	105	96	1	0	9
	2017	477	250	201	6	0	20
Small Hotel/Motel	2012	118	75	38	0	0	6
	2017	265	170	82	1	0	13
Contract Hospital	2012	457	320	104	1	0	32
	2017	998	712	214	5	1	66
Hospital	2012	925	700	189	3	0	33
	2017	2,055	1,582	390	13	1	69
Nursing Home	2012	1,238	796	375	9	0	59
	2017	2,848	1,897	784	38	0	128
School	2012	3,058	2,801	239	6	0	13
	2017	7,289	6,722	513	26	0	28
Contract University/College	2012	582	457	91	3	1	31
	2017	1,307	1,042	187	12	1	65
University/College	2012	199	163	28	1	0	6
	2017	447	372	59	3	0	13
Restaurant/Food Service	2012	528	343	154	29	0	2
	2017	1,356	900	332	122	0	3
Warehouse	2012	257	242	9	0	0	5
	2017	571	537	21	0	0	12
High-rise Apartment	2012	1,195	807	370	0	0	18
	2017	2,666	1,841	783	2	0	40
Mid-rise Apartment	2012	1,145	764	372	1	0	9
	2017	2,565	1,740	802	4	0	19
Other Buildings	2012	2,280					
	2017	5,388					
Other Contract Institutional Buildings	2012	1,096					
	2017	2,680					
Total	2012	26,749	19,333	3,133	65	1	841
	2017	63,310	46,348	6,766	273	3	1,851

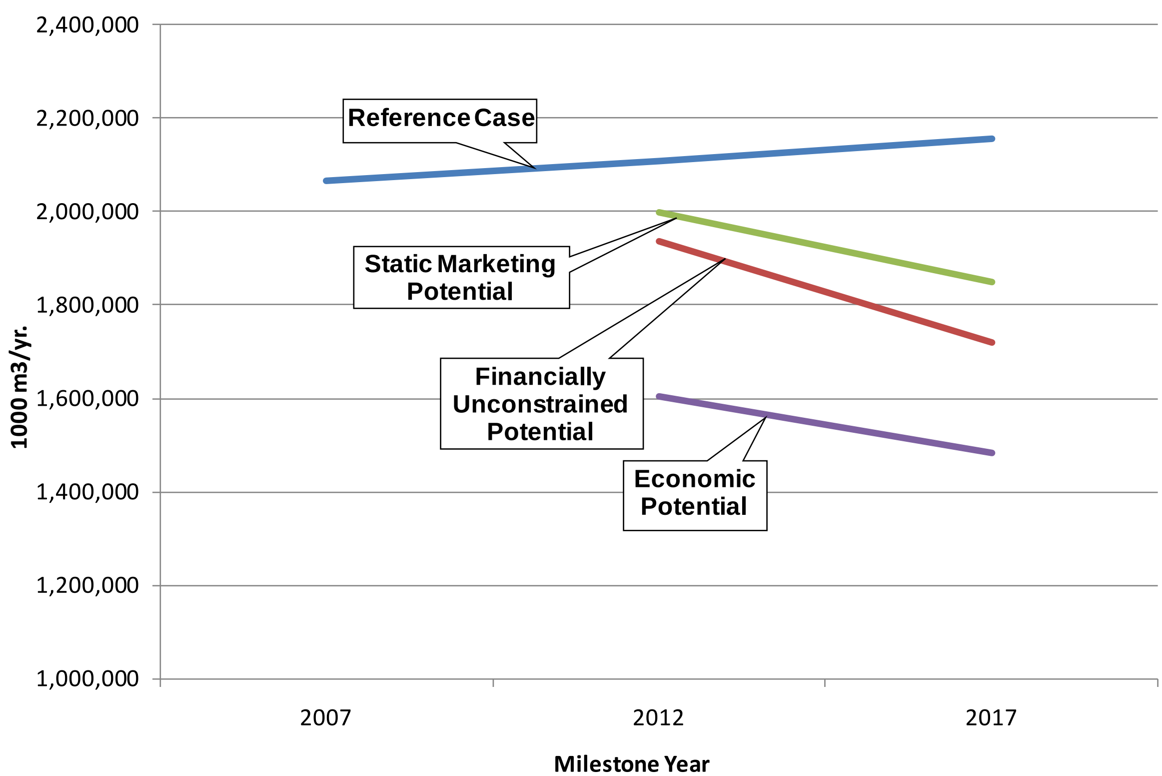
Exhibit 6.20: Annual Natural Gas Savings and Estimated Program Costs by Major Measure Type for One Year of Program Activity (2017) - Total Union Service Area, Static Marketing Scenario

Measure Bundle	Static Marketing Potential 2017		Program Costs, 2017 (1000 $)	Program Costs per Unit	
	Gas Savings (1000 m^3/yr.)	TRC Benefits (1000 $)		per Natural Gas Savings ($/$m^3$)	per TRC Benefits ($/$)
Efficient Food Service Equipment	255	363	163	$0.64	$0.45
Space Heating - Envelope measures (Conductive)	952	1,303	98	$0.10	$0.07
Space Heating - Envelope measures - Air Sealing	1,020	1,257	171	$0.17	$0.14
Space Heating / Other - Recommissioning	14,276	52,103	1,058	$0.07	$0.02
Space Heating - Ventilation Measures - Heat Recovery	5,932	12,971	3,492	$0.59	$0.27
Space Heating - Equipment	1,528	3,480	430	$0.28	$0.12
DHW - Conservation Measures	3,888	17,117	1,104	$0.28	$0.06
DHW - Equipment Measures	473	922	191	$0.40	$0.21
New construction - 40% Better	1,293	10,350	85	$0.07	$0.01
Weighted Average				$0.23	$0.07

6.7 SUMMARY AND INTERPRETATION OF RESULTS

Exhibit 6.21 provides a summary of the achievable natural gas savings under the Static Marketing and Financially Unconstrained scenarios presented in the preceding section. Results are shown relative to the Reference Case and Economic Potential Forecasts.

Exhibit 6.21: Achievable Potential, Reference Case and Economic Potential Forecasts for the Total Union Service Area



Further highlights are provided below.

The Financially Unconstrained Scenario

- Under the conditions defined by this scenario, total Commercial sector natural gas savings in 2017 are estimated to be approximately 390 million m^3/yr. This represents a saving of approximately 18%, relative to the Reference Case, and is equal to approximately 62% of the savings identified in the Economic Potential Forecast.

- The most significant opportunities for natural gas savings in this scenario are technologies that reduce space heating requirements. Approximately 80% of savings identified in this scenario come from the space heating end use; approximately 16% come from the water heating end use. Building recommissioning and advanced BAS systems are, however, a particularly large opportunity in this scenario.

- Program costs per m^3 of natural gas savings in this scenario range widely by measure, from approximately $0.11 for efficient new construction measures to over $1.00 for efficient food service equipment measures.

- Program costs per dollar of TRC benefit also show a wide range, from approximately $0.01 for efficient new construction measures to $0.80 for air efficient food service equipment measures.

- Weighted averages for the whole group of measures show 2017 program costs of approximately $0.30/$m^3$ of natural gas savings and approximately $0.09/TRC dollar. These values are approximately 110% and 50% higher, respectively, than Union's current program results.[175]

The Static Marketing Scenario

- Under the conditions defined by this scenario, total Commercial sector natural gas savings in 2017 are estimated to be approximately 259 million m^3/yr. This represents a saving of approximately 12%, relative to the Reference Case, and is equal to approximately 42% of the savings identified in the Economic Potential Forecast.

- The most significant opportunities for natural gas savings in this scenario are technologies that reduce space heating requirements. Approximately 78% of savings identified in this scenario come from the space heating end use; approximately 17% come from the water heating end use. Again, building recommissioning and advanced BAS systems are a particularly large opportunity in this scenario.

- Program costs per m^3 of natural gas savings in this scenario range widely by measure, from approximately $0.07 for efficient new construction measures to $0.64 for efficient food service equipment measures.

[175] Union's audited results for its 2006 commercial DSM programs show that program spending of $3,090,000 achieved natural gas savings of 22,053,000 m^3 and TRC net benefits of $53,319,000. Expressed as a ratio, one dollar of program spending generated approximately 7.1 m^3 (approximately $0.14/$m^3$) of annual natural gas savings and over $17 of TRC net benefits (approximately $0.06/TRC $).

- Program costs per dollar of TRC benefit also show a wide range, from approximately $0.01 for efficient new construction measures to $0.45 for air efficient food service equipment measures.

- Weighted averages for the whole group of measures included in this scenario show 2017 program costs of approximately $\$0.23/m^3$ of natural gas savings and approximately $0.07/TRC dollar. These values are approximately 65% and 20% higher, respectively, than Union's current program results.

Comparison of Scenarios

Changes in the distribution of savings potential can be detected as the analysis moves from Economic Potential Scenario to the two achievable potential scenarios. The following observations may be made:

- Implementation of measures is spread out more evenly in the achievable scenarios. In the Economic Potential scenario savings are "front loaded" because measures that pass at full cost are assumed to be implemented immediately. This does not occur to the same extent in the achievable scenarios because measure uptake ramps up slowly, taking into account market constraints.

- Savings by end use shift slightly when moving from one scenario to another. In particular, Space Heating potential accounts for a slightly smaller proportion of the overall savings as the analysis moves from Economic Potential to Financially Unconstrained Potential and then to Static Marketing Scenario. In contrast, Water Heating measures increase slightly relative importance. This is largely due to the assumptions about participation rates for the individual measures, arrived at during the achievable potential workshop.

- There is no dramatic shift in the proportion of savings by region moving from one scenario to another.

- A slight variation is observed with respect to the various subsectors when moving from one scenario to another. This is primarily due to two factors:

    - Participation rates in the more homogenous sub sectors, sub sectors with larger average building sizes, and those sub sectors with high levels of public ownership were generally estimated to be higher during the achievable potential workshop. These sub sectors therefore tended to have slightly higher proportion of the overall savings as the analysis moves from Economic Potential to Financially Unconstrained Potential and then to Static Marketing Scenario.

    - Sub sectors whose Water Heating gas consumption is higher than average (i.e. apartment buildings and hotels) tended to have a slightly higher proportion of the overall savings as the analysis moves from Economic Potential to Financially Unconstrained Potential and then to Static Marketing Scenario.

- The relative importance of the different measure types changes significantly from one scenario to another. Within the Economic Potential Scenario, the largest potential for natural gas savings in 2017 is contributed by Recommissioning & Advanced BAS, Hot Water Conservation and Efficient New Construction. These measure categories make up 35%, 11%, and 9% of savings respectively.

- For measures that pass the TRC screen on an incremental cost basis, low participation rates in early milestone years create a significant "lost opportunity." This is particularly relevant to the replacement of equipment with a very long life (i.e. space heating equipment), building renovations such as envelope improvements, and new building construction.

    - Due largely to this phenomenon, the contribution of those measures introduced immediately (i.e. full cost measures) become relatively more important under the both of the achievable scenarios.

    - In the unconstrained scenario, the two largest full cost measure types (Recommissioning and Hot Water Conservation) increase in importance, while the largest full cost measure (Efficient New Construction) decreases in relative importance. These measure categories make up 48%, 13%, and 5% of unconstrained savings respectively.

    - In the static marketing scenario, the trend is more pronounced. Recommissioning, Hot Water Conservation and Efficient New Construction make up 55%, 15%, and 3% of savings respectively.

7. CONCLUSIONS

This study has confirmed the existence of significant cost-effective DSM potential within all sub sectors of Union's Commercial sector.

Although the weighted average program cost values presented for both the Financially Unconstrained and Static Marketing scenarios will vary depending on the specific composition of the future program portfolio, both scenarios show an evident trend towards higher future costs to achieve natural gas savings and TRC benefits.[176] This trend recognizes that savings from DSM programs tend to become more expensive with time as the most attractive measures gain greater market penetration and only the more challenging measures remain.[177]

7.1 ADDITIONAL OBSERVATIONS

In addition to the preceding conclusions, three additional observations warrant note as they may affect future program strategies. They include:

- ***Rate of measure implementation has a large effect on overall savings:*** For measures that pass the TRC screen on an incremental cost basis, low participation rates in early milestone years create a significant "lost opportunity." This is particularly relevant to the replacement of equipment with a very long life (i.e. space heating equipment), building renovations such as envelope improvements, and new building construction. The gap between Economic Potential and Achievable Potential savings presented in this study is due in large part to this significant lost opportunity that occurs in early milestone years.

- ***Savings arising from full cost measures may be delayed without eroding overall potential:*** This is a corollary of the above point, and most pertinent to the discussion of the largest opportunity identified in this study, recommissioning. As recommissioning passes the TRC screen at full cost, eligible buildings which are not recommissioned remain as future opportunities, while incremental cost opportunities which are not exploited represent lost opportunities. This may be especially relevant to programming strategy during periods of economic downturn, when building owners and managers may be less likely to implement measures despite an attractive payback.

- ***Market transformation approaches warrant additional consideration:*** There are a number of technically mature measures that do not currently pass the TRC screen. The largest share of these additional potential savings are from air sealing and envelope upgrades, including wall insulation and more energy efficient glazing measures in existing buildings. These measures do not pass the TRC screen as currently defined. However, they provide non-energy benefits such as increased comfort and reduced noise that are not currently captured in the TRC calculation. In addition, industry specialists emphasized that some emerging technologies, such as solar preheated make-up air may be better addressed in a market transformation context. They provide "soft" benefits, such

[176] Design of a DSM program portfolio is beyond the scope of this current study.

[177] Over time, it is also expected that some relatively new technologies may become less expensive as they gain greater sales volumes.

as visible contribution to corporate greening goals, which are not included in the TRC calculation.

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9. GLOSSARY

achievable potential
The Achievable Potential is the proportion of the natural gas savings identified in the Economic Potential Forecast that could realistically be achieved within the study period. Achievable Potential recognizes that it is difficult to induce customers to purchase and install all of the efficiency technologies that meet the criteria defined by the Economic Potential Forecast.

avoided cost
The unit cost of acquiring the next resource to meet demand, which is used as a measure for evaluating individual demand-side and supply-side options. In the context of this study "avoided cost" is the capital expenditure offset by Union Gas DSM activities (i.e., the cost of having to buy natural gas on the open market, contract for long-term supply, and/or build and run new storage/transmission facilities).

base year
The Base Year is the year to which all potentials will be compared. It provides a detailed description of "where" and "how" natural gas is currently used in each sector. For this study, it is the calendar year 2007. The modelled base year energy use is calibrated against Union's actual sales for 2007.

benefit/cost ratio
The measure benefit/cost ratio indicates the relative attractiveness of the measures. A measure that has a benefit/cost ratio in excess of 1.0 has benefits which outweigh its costs. Similarly, a measure with a benefit/cost ratio that is well in excess of one (e.g., 3.0) means that it is very attractive. A measure with a benefit/cost ratio of less than 1.0 has costs which outweigh its benefits.

building envelope
The material separation between the interior and the exterior environments of a building. The building envelope serves as the outer shell to protect the indoor environment as well as to facilitate its climate control.

co-generation
The simultaneous production of electric or mechanical energy and useful heat energy from a single fuel source.

combustion efficiency
The ratio of energy released during combustion to the potential chemical energy available in the fuel.

demand-side management (DSM)
Actions that modify customer demand for natural gas and that can defer the need for additional new supply.

discount rate
The interest rate used in calculating the present value of expected yearly benefits and costs.

economic efficiency
Allocation of human and natural resources in a way that results in the greatest net economic benefit, regardless of how benefits and costs are distributed within society.

economic potential forecast
The economic potential forecast is an estimate of the level of natural gas consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost effective from society's perspective. All of the energy-efficiency technologies and measures that have a positive measure TRC are incorporated into the economic potential forecast. These technologies and measures are applied at either natural stock turnover rates or at designated years for immediate application.

effective measure life (EML)
The estimate median number of years that the measures installed under a program are still in place and operable. EML incorporates field conditions, obsolescence, building remodelling, renovation, demolition and occupancy changes.

energy audit
An on-site inspection and cataloguing of energy using equipment/buildings, energy consumption and the related end-uses. The purpose is to provide information to the customer and the utility. Audits are useful for load research, for DSM program design and for identification of specific energy savings projects.

energy conservation
Activities by energy users that result in a reduction of the energy used to provide services. Energy conservation can include a wide variety of behavioural or operational changes that result in energy savings. For the purpose of this study, only energy savings achieved through physical or hardware installations are considered.

energy intensity
The ratio of energy consumed per application or end use. For example, gigajoules per square metre of heated office space per day, or gigajoules per tonne of aluminum produced. All else being equal, energy intensity increases as energy efficiency decreases.

emerging technologies
New energy-conserving technologies that are not yet market-ready, but may be market-ready over next 5 to 10 years. This category includes technologies that could be accelerated into the market during that period through targeted financial or technical support.

end use
The final application or final use to which energy is applied. End use is often used interchangeably with energy service.

energy savings
The savings that result from efficient technologies or activities. In this document, the term "energy" refers specifically to energy derived from natural gas unless otherwise noted.

energy service
An amenity or service supplied jointly by energy and other components/equipment such as buildings and heating equipment. Examples of energy services include residential space heating, commercial cooking, aluminum smelting and public transit. The same energy service can frequently be supplied with different mixes of equipment and energy.

energy use index (EUI)
End use energy consumption divided by a specific parameter of production (e.g., MJ/m^2., MJ/unit).

environmental credit/environmental penalty
An increment or decrement to the cost of a resource or set of resources, to reflect the overall level of its/their environmental impact, relative to another resource or set of resources.

financial incentive
Certain financial features in the utility's DSM programs designed to motivate customer participation. They may include features designed to reduce a customer's net cash outlay, pay-back period or cost of finance to participate.

fuel share
The proportion of requirements for a specific service met using a certain fuel. For example, a natural gas fuel share of 90% for space heating in commercial large office sub sector implies that 90% of the sub sector floor space is heated using natural gas. Similarly, a 90% natural gas fuel share in single family detached homes means that 90% of the space heating requirements for that dwelling type are met by natural gas.

gigajoule
One billion joules or one thousand megajoules.

interactive effects
In the context of natural gas use, interactive effects refer to the increase in gas consumed by heating equipment required to offset a decrease in "waste" heat generated by more efficient electrical fixtures or appliances after retrofit or replacement.

joule
The basic unit of energy. In physical terms, equal to the work required to move a mass of one Newton a distance of one metre.

kilowatt (kW)
One thousand watts; the most common unit of measurement of electric power. (The amount of energy transferred at a rate of one kilowatt for one hour is equal to one kilowatt hour.)

kilowatt hour (kWh)
The most common unit of measurement of electric energy. One kilowatt hour represents the power of one thousand watts for a period of one hour.

load forecast
An estimate of expected natural gas requirements that have to be met by the utility in future years.

load research
Research to disaggregate and analyze patterns of natural gas consumption by various sub sectors and end-uses. Load Research supports the development of the load forecast and the design of demand-side management programs.

measure total resource cost (TRC)
The Measure TRC is the net present value of energy savings that result from an investment in a energy efficiency measure. The Measure TRC is equal to its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy and operating & maintenance costs. This calculation includes among others, the following inputs: the avoided natural gas and electricity supply costs; the life of the measure; and the selected discount rate.

megajoule
One million joules.

natural conservation
The future change in energy intensity that is expected to occur in the absence of utility DSM programs.

non-participant test (NPT)
A test measuring what happens to rates due to changes in utility revenues and operating costs caused by a program. Rates will go down if the avoided cost is greater than the sum of the revenue lost plus the program costs. This test indicates the direction and magnitude of the expected change in rate levels.

rate
Generically refers to a utility's rate structure.

rate structure
The formulae used by a utility to calculate charges for the use of natural gas or electricity.

reference case forecast
An estimate of the expected level of natural gas consumption that would occur over the study period in the absence of any new utility DSM market interventions after 2008. It is the baseline against which the scenarios of energy savings are calculated. The Reference Case forecast incorporates an estimation of "natural conservation," namely, changes in end-use efficiency over the study period that are projected to occur in the absence of new market interventions by the utility.

saturation
The portion of floor area that receives a specific energy service. For example, a saturation of 86% for space cooling in the Large Office sub sector means that 86% of the sub sector floor space is cooled (regardless of fuel used to provide that cooling).

seasonal efficiency
The ratio of delivered useful energy relative to the input potential fuel energy determined over a full heating season (or year).

sector
A group of customers having a common type of economic activity. Union Gas divides its customers into three principal sectors: Residential, Commercial and Industrial. Sectors are further divided into sub sectors. For example, “Large Offices” is a sub sector of the Commercial sector.

service area
The portion of the Province of Ontario that receives service from Union Gas. Union Gas’ service area is spread across the Province of Ontario including northern, southwestern and southeastern cities and towns.

service region
For the purposes of this study, the total Union Gas service area is divided into two service regions. They are the Northern Region and Southern Region.

simple payback
The simple payback is generated to show the customer’s financial perspective. Simple payback is a measure of the length of time required for the cumulative savings from a project to recover its initial investment cost and other accrued costs, without taking into account the time value of money.

strategic conservation
Utility action to reduce the total natural gas demand. Strategic conservation is natural gas conservation induced by utility programs.

strategic load growth
Utility action to increase (annual) total natural gas demand for specific end uses.

sub sectors
A classification of customers within a sector by common features. Residential sub sectors are by type of home (SFD, duplex, apartment, etc.). Commercial sub sectors are generally by type of commercial service (office, retail, warehouse, etc.). Industrial sub sectors are by product type (pulp and paper, solid wood products, chemicals, etc.).

supply curves
A curve illustrating the amount of energy available at an appropriate screened price in ascending order of cost.

Total Resource Cost (TRC) Test
A test that compares the total costs of energy efficiency investments, including natural gas conservation programs, to the social cost of natural gas. Un-priced environmental and social costs may be accounted for by changing the cost of either the investment under consideration or the total cost of natural gas in such a way that relative un-priced impacts are reflected. It is used in designing and evaluating programs that are developed from the Energy Efficiency Potential study's results.

utility cost
The total financial cost incurred by the utility to acquire energy resources. For DSM, the costs include all utility program costs, including incentive costs.

watt
The basic unit of measurement of power.

Natural Gas
Energy Efficiency Potential

Industrial Sector

–Final Report–

Submitted to:

Union Gas

Submitted by:

Marbek Resource Consultants Ltd.

March 24, 2009

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Note to Reader

The primary economic data for this study was compiled during the period April to June of 2008. They represented the best available at the time. However, since that time, Canada and other global economies have entered a period of unprecedented economic uncertainty that may have significant impact on the results of this study, particularly in the short term. Three elements that affect this study's results are particularly impacted by these economic changes:

- Sector growth rates
- DSM Program participation rates that are used to determine the estimates of achievable potential
- Type of DSM investment

Sector Growth Rates

Key factors underlying Union's load forecast and the study's Reference Case such as gross domestic product (GDP), energy prices, commodity prices, currency values etc. are expected to change under the current conditions. The impact of these changes, at least in the short term, is expected to be reduced industrial output accompanied by reduced consumption of natural gas. At this time, it is impossible to predict either the extent or the duration of the economic downturn and its consequent impact on natural gas consumption.

DSM Program Participation Rates

The participation rates estimated during the Achievable Potential workshops do not explicitly take into account changes in industry outlook as a result of the economic downturn. In the short term, the expected impact would be lower discretionary investment and, hence, lower program participation rates than those presented in this report. As neither the extent nor the duration of the economic downturn is known at this time, it is not possible to estimate the total reduction in program participation rates over the full study period.

Type of DSM Investment

Many of the DSM investments included in this study's results pass the economic screen on a full cost basis and can be implemented at any time over the study period. This means that even if program participation rates are reduced in the short term, there remains the possibility of recapturing some of these opportunities in later portions of the study period. However, some of the DSM investment opportunities included in the study's results occur only when existing equipment is replaced at the end of its life. This means that if program participation rates are reduced in the short term, then the opportunity to implement the energy efficient model is lost until the equipment again comes up for replacement, which in most applications will be beyond the period covered by this study.

EXECUTIVE SUMMARY

❑ Background and Objectives

Union Gas Ltd. (Union) is a natural gas utility serving almost 1.3 million customers in the residential, commercial and industrial markets. Union is a regulated utility with a franchise area spread across the Province of Ontario, including northern, southwestern and southeastern cities and towns. Union distributes approximately 13.9 billion m^3 (489.9 billion ft^3) of natural gas to its customers annually.

Since 1997, Union has delivered demand side management (DSM) programs to its customers under a mandate from the provincial regulator, the Ontario Energy Board (OEB). Union offers DSM programs to all in-franchise customer rate classes and across all sectors and the DSM savings target and budget are determined through a rate proceeding with the OEB. Over the past eleven years Union has delivered approximately 614 million m^3 of natural gas savings and over $1 billion in net Total Resource Cost (TRC) benefits.

Union has been participating in a market of increasing DSM program maturity. This market is continually evolving in its engagement with energy efficiency through growing voluntary initiatives and more stringent codes and standards. In addition, changes in the economy have started to show signs of negatively impacting the commercial and industrial marketplace in Union's Service Area.

In the DSM Generic Proceeding held in 2006, Union committed to creating an updated Market Potential Study for input into the next DSM plan. This study will support the identification of potential energy savings for Union's next multi-year plan and be part of Union's regulatory filing in the next DSM rate case.

Union has initiated this current study within the context of the conditions noted above. When completed, the results of this natural gas Efficiency Potential Study will provide a foundation that Union can use to guide the development of its longer-term DSM strategy, including new measures and targets.

In the DSM Generic Proceeding held in 2006, Union committed to creating an updated Market Potential Study for input into the next DSM plan. Union has initiated this current study within the context of the conditions noted above. When completed, the results of this Natural Gas Efficiency Potential Study will provide a foundation that Union can use to guide the development of its longer-term DSM strategy, including new measures and targets. More specifically, this includes support for Union's filing to the OEB regulatory application for the next multi-year DSM plan by:

- Estimating the achievable and economic potential for DSM measures across all applicable technologies, markets and sectors in Union's Service Area

- Giving shape to, and refining ongoing energy-efficiency work by Union in order to develop its next multi-year DSM plan, and

- Provide information that is actionable and can be easily converted to plan and program development.

❑ Scope and Organization

This study covers a 10-year study period from 2007 to 2017 and addresses the Residential, Commercial and Industrial sectors. The 2007 calendar year was selected as the Base Year as this is the most recent year for which complete customer data are available.

The study addresses the full range of natural gas efficiency measures. Results are presented for the total Union Service Area and for two service regions: The study results are disaggregated by service region due to differences in the distribution of industry sub sectors.

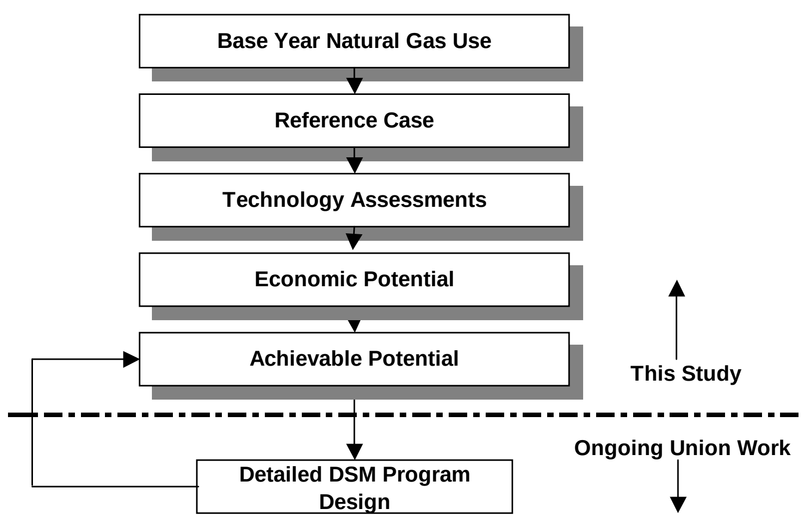
This report presents the results for Union's Industrial sector.

❑ Approach

The detailed end-use analysis of energy-efficiency opportunities in the Industrial sector employed Marbek's Industrial Energy-efficiency Model (IEEM), an in-house spreadsheet-based macro model. The model is described in further detail in Section 1.

The major steps involved in the analysis are shown in Exhibit ES1 and are discussed in greater detail in Section 1. As illustrated in Exhibit ES1, the results of this study, and in particular the estimation of Achievable Potential,[1] support Union's on-going DSM program planning; however, it should be emphasized that the estimation of Achievable Potential is not synonymous with either the setting of specific targets or with detailed program design, which are beyond the scope of this study.

Exhibit ES1: Study Approach - Major Analytical Steps



❑ Overall Study Findings

As in any study of this type, the results presented in this report are based on a large number of important assumptions. Assumptions such as those related to the current penetration of energy-efficient technologies, the rate of future growth in the province's industrial sectors and customer

[1] The proportion of savings identified that could realistically be achieved within the study period, under various program spending and market conditions.

willingness to implement new efficiency measures are particularly influential. Wherever possible, the assumptions used in this study are consistent with those used by Union and are based on best available information, which in many cases includes the professional judgement of the consultant team, Union personnel and local experts. The reader should, therefore, use the results presented in this report as best available estimates; major assumptions, information sources and caveats are noted throughout.

The study findings confirm the existence of significant cost-effective DSM potential in Union's Industrial sector. Natural gas savings from efficiency improvements within the Union Service Area would provide between 846 and 524 million m^3/year of natural gas savings by 2017 in, respectively, the Financially Unconstrained and the Static Marketing Achievable scenarios. The most significant Achievable Savings opportunities were in the actions that reduce gas usage for process heating (specifically for ovens, dryers, furnaces and kilns), boiler steam systems and plant-wide systems.

Although program costs for the Financially Unconstrained and the Static Marketing scenarios will vary depending on the specific composition of the future program portfolio, both scenarios show an evident trend towards higher future costs to achieve natural gas savings and TRC benefits.[2] This trend recognizes that savings from DSM programs tend to become more expensive over time, as the most attractive measures gain greater market penetration and only the more challenging measures remain.[3]

- ❑ Summary of Natural Gas Savings

A summary of the levels of annual natural gas consumption contained in each of the forecasts addressed by the study is presented in Exhibits ES2 and ES3, by milestone year, and discussed briefly in the paragraphs below.

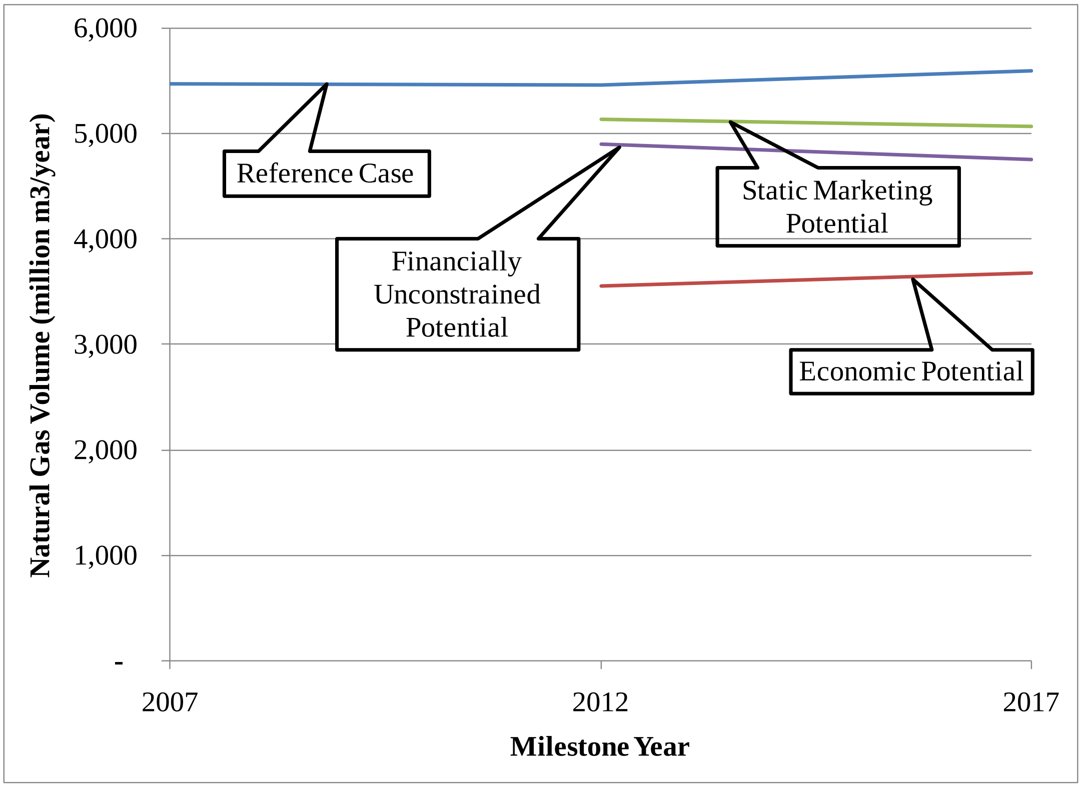
Exhibit ES2: Summary of Forecast Results for the Total Union Service Area – Annual Natural Gas Consumption and Savings, Industrial Sector (million m^3/yr.)

Annual Consumption in Industrial Sector (million m^3/yr.)					Potential Annual Savings (million m^3/yr.)		
Milestone Year	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Financially Unconstrained	Static		Financially Unconstrained	Static
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2007	5,465	-	-	-	-	-	-
2012	5,458	3,555	4,901	5,141	1,903	557	318
2017	5,598	3,675	4,752	5,074	1,923	846	524

2 Design of a DSM program portfolio is beyond the scope of this current study.

3 Over time, it is also expected that some relatively new technologies, such as condensing boilers, may become less expensive as they gain greater sales volumes.

Exhibit ES3: Graphic of Forecast Results for the Total Union Service Area – Annual Natural Gas Consumption, Industrial Sector (million m^3/yr.)



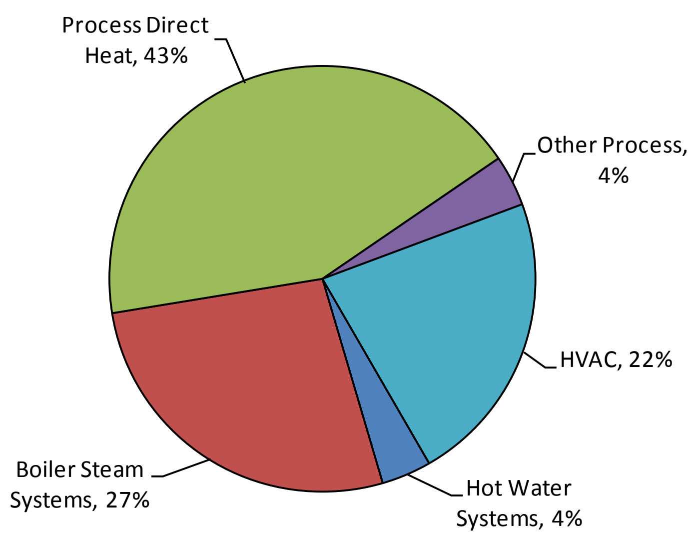
Base Year Natural Gas Use

In the Base Year of 2007, Union's Industrial sector consumed about 5,465 million m^3 of natural gas. Exhibit ES4 shows that process direct heat accounts for about 43% of total industrial natural gas use. Boiler steam systems account for about 27% of the total natural gas use, followed by heating, ventilation and cooling (HVAC) (22%) and hot water systems (4%). The remaining 4% of natural gas consumption occurs in a variety of other processes that are sub sector specific, such as using gas for steam generation in steam dryers.

Exhibit ES4: Base Year Natural Gas Use by End Use for the Total Union Service Area, Industrial Sector (1000 m^3/yr.)

Sub Sector	End Use						
	Hot Water Systems	Boiler Steam Systems	Process Direct Heat	Other Process	HVAC	Total	
Contract Primary Metal	27,568	161,964	963,099	31,428	194,357	1,378,415	25%
Contract Chemical	20,117	408,369	331,925	74,222	171,201	1,005,834	18%
Other Chemical	741	15,034	12,220	2,732	6,303	37,030	0.7%
Contract Paper	11,344	353,887	107,431	10,380	84,175	567,218	10%
Contract Transportation and Machinery	7,827	91,046	117,313	15,868	159,278	391,332	7%
Other Transportation and Machinery	2,984	34,718	44,734	6,051	60,736	149,223	3%
Contract Petroleum Refineries	7,520	72,251	253,607	6,738	35,873	375,989	7%
Contract Mining	64,023	80,029	112,041	16,006	48,017	320,117	6%
Other Mining	5	6	9	1	4	25	0.0004%
Contract Food and Beverage	20,142	120,397	69,212	15,585	26,436	251,771	5%
Other Food and Beverage	4,463	26,680	15,337	3,454	5,858	55,793	1%
Contract Non-Metallic Mineral	5,598	33,477	198,345	10,581	31,910	279,911	5%
Miscellaneous Industrial	33,945	75,984	127,031	17,690	398,131	652,781	12%
Total	206,277	1,473,842	2,352,303	210,736	1,222,280	5,465,438	
%	4%	27%	43%	4%	22%		

Note: Totals may not add to 100% due to rounding.



Roughly 25% of the natural gas consumption in the Industrial sector is used by the Contract Primary Metal sub sector. The Contract Chemical sub sector uses about 18%, followed by Miscellaneous Industrial (12%), and Contract Paper (10%). The Southern service region accounts for nearly 70% of the industrial natural gas consumption in the total Union Service Area.

Reference Case

In the absence of new Union DSM initiatives, the study estimates that natural gas consumption in Union's Industrial sector will grow from 5,465 million m^3 in 2007 to about 5,598 million m^3 by 2017. This represents an overall growth of about 2.4% in the period and compares very closely with Union's load forecast, which also included consideration of the impacts of "natural conservation."

Economic Potential Forecast

Under the conditions of the Economic Potential Forecast,[4] the study estimated that natural gas consumption in Union's Industrial sector would decline from the Base Year levels of 5,465 million m^3 to about 3,675 million m^3 by 2017. Annual savings in 2017 relative to the Reference Case are 1,923 million m^3, or about 34%.

Achievable Potential

As noted above, the Achievable Potential is the proportion of the economic natural gas savings that could practically be achieved within the study period under various program spending and marketing conditions.

Under the conditions defined by the Financially Unconstrained scenario, total Industrial sector natural gas savings in 2017 are estimated to be approximately 846 million m^3/year. This represents a savings of approximately 15%, relative to the Reference Case, and is equal to approximately 44% of the savings identified in the Economic Potential Forecast.

The most significant opportunities for natural gas savings in this scenario are technologies that reduce gas usage for process heating, specifically ovens, dryers, kilns and furnaces. Implementation of energy-efficiency measures in boiler steam systems is also a significant opportunity. Measures that improve the total plant (referred to as system wide) energy efficiency are the third most significant opportunity area.

Under the conditions defined by the Static Marketing scenario, total Industrial sector natural gas savings in 2017 are estimated to be approximately 524 million m^3/yr. This represents a savings of approximately 9%, relative to the Reference Case and is equal to approximately 27% of the savings identified in the Economic Potential Forecast.

Similar to the Financially Unconstrained scenario, the most significant opportunities for natural gas savings are technologies and measures applicable to process heating, boiler steam systems and system wide (or plant wide).

[4] The level of natural gas consumption that would occur if all equipment and systems were upgraded to the level that is cost effective. In this study, "cost effective" means that the technology upgrade passes the measure TRC test.

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List of Exhibits

1. INTRODUCTION

1.1 BACKGROUND AND OBJECTIVES

Union Gas Ltd. (Union) is a natural gas utility serving almost 1.3 million customers in the residential, commercial and industrial markets. Union is a regulated utility with a franchise area spread across the Province of Ontario including northern, southwestern and southeastern cities and towns. Union distributes approximately 13.9 billion m^3 (489.9 billion ft^3) of natural gas to its customers annually.

Since 1997, Union has delivered demand side management (DSM) programs to its customers under a mandate from the provincial regulator, the Ontario Energy Board (OEB). Union offers DSM programs to all in-franchise customer rate classes and across all sectors and the DSM savings target and budget are determined through a rate proceeding with the OEB. Over the past eleven years Union has delivered approximately 614 million m^3 of natural gas savings and over $1 billion in net Total Resource Cost (TRC) benefits.

Union has been participating in a market of increasing DSM program maturity. This market is continually evolving in its engagement with energy efficiency through growing voluntary initiatives and more stringent codes and standards. In addition, changes in the economy have started to show signs of negatively impacting the commercial and industrial marketplace in Union's Service Area.

In the DSM Generic Proceeding held in 2006, Union committed to creating an updated Market Potential Study for input into the next DSM plan. This study will support the identification of potential energy savings for Union's next multi-year plan and be part of Union's regulatory filing in the next DSM rate case.

Union has initiated this current study within the context of the conditions noted above. When completed, the results of this natural gas Efficiency Potential Study will provide a foundation that Union can use to guide the development of its longer-term DSM strategy, including new measures and targets. More specifically, this includes support for Union's filing to the OEB regulatory application for the next multi-year DSM plan by:

- Estimating the achievable and economic potential for DSM measures across all applicable technologies, markets and sectors in Union's Service Area.
- Giving shape to, and refining, ongoing energy-efficiency work by Union in order to develop its next multi-year DSM plan.
- Provide information that is actionable and can be easily converted to plan and program development.

1.2 STUDY SCOPE

The scope of this study is summarized below.

Sector Coverage: The study addresses three sectors: Residential, Commercial and Industrial.

Geographical Coverage: The study results are presented for the total Union Service Area and for two service regions: Southern and Northern. The southern region of Union's system extends through Southwestern Ontario from Windsor to just west of Toronto. The Northern region of Union's system extends throughout Northern Ontario from the Manitoba border to the North Bay/Muskoka area and across Eastern Ontario from Port Hope to Cornwall. The study results are disaggregated by service region due to differences in building stock and weather conditions (heating degree days).

Study Period: This study covers a 10-year period. The Base Year is the calendar year 2007, with milestone periods at five-year increments: 2012 and 2017. The Base Year of 2007 was selected, as this was the most recent calendar year for which complete customer data were available.

Technologies: The study addresses the full range of natural gas energy-efficiency measures. All the measures that were assessed in the study are summarised in Exhibit 1.1. In consultation with Union, some measures were combined, such as boiler right sizing and load management. Two measures, first generation super boiler and computational fluid dynamic (CFD) modeling, were screened out end excluded from the study. First generation super boilers are an emerging technology and its application and potential market take up is considered to be too uncertain, and potentially very limited, for inclusion in the potential analysis. CFD is a tool to identify improvement projects and the resulting measures are captured by existing measures. Inclusion of CFD would result in double counting the savings. More detailed description of the measures and the technologies included in the measures are provided in Section 4.

1.2.1 Data Caveat

As in any study of this type, the results presented in this report are based on a large number of important assumptions. Assumptions such as those related to the current penetration of energy-efficient technologies, the rate of future growth in Union's industrial load and customer willingness to implement new energy-efficiency measures are particularly influential.

Wherever possible, the assumptions used in this study are consistent with those used by Union and are based on best available information, which in many cases includes the professional judgment of the consultant team, Union personnel and/or local experts. The reader should use the results presented in this report as best available estimates; major assumptions, information sources and caveats are noted throughout.

Exhibit 1.1: Industrial Energy-Efficiency Technologies

End Use	Energy Management Measure List
System	Integrated control system
	Sub-metering
Boilers, Steam and Hot Water Systems	Economizer
	Blowdown heat recovery
	Boiler combustion air preheat
	Process heat recovery to pre-heat make-up water
	Condensing boiler
	First generation super boilers
	Direct contact hot water heaters
	Boiler right sizing and load management
	High-efficiency burners
	Insulation
	Advanced boiler controls
	Blowdown control
	Boiler water treatment
	Boiler maintenance
	Minimize deaerator vent losses
	Condensate return
	Steam trap survey and repair
	Instantaneous steam generation
Process Direct Heat (Furnaces / Kilns / Ovens / Dryers)	Exhaust gas heat recovery
	High-efficiency burners and burner controls
	Oxy-gas direct impingement heating for steel annealing
	Insulation
	Advanced heating and process control
	High-efficiency ovens
	High-efficiency dryers
	High-efficiency kilns
	High-efficiency furnaces
	Air curtains
Other Process	Pollution control measures
	Computational fluid dynamic modeling
	Hydrogen atmospheres for steel batch coil annealing
	Process Heat Recovery
HVAC	Radiant heaters
	Automated temperature control
	Solar walls
	Ventilation heat recovery & optimization
	Warehouse loading dock seals
	Air curtains
	Air compressor heat recovery
	Destratification fans

1.3 DEFINITIONS[5]

This study employs numerous terms that are unique to analyses such as this one and consequently it is important to ensure that readers have a clear understanding of what each term means when applied to this study. Below is a brief description of some of the most important terms.

Base Year Natural Gas Use The Base Year of 2007 is the starting point for the analysis. It provides a detailed description of "where" and "how" natural gas is currently used in the Industrial sector. A bottom up profile of energy use patterns and market shares of energy-using technologies was calibrated to actual Union customer billing data.

Reference Case Forecast The Reference Case is a projection of natural gas consumption to 2017, in the absence of any new Union DSM market interventions after 2007. It is the baseline against which the scenarios of energy savings are calculated. The Reference case forecast incorporates an estimation of "natural conservation," namely, changes in end-use efficiency over the study period that are projected to occur in the absence of new market interventions. The Reference Case, therefore, provides the point of comparison for the calculation of opportunities associated with each of the subsequent scenarios that are assessed within this study.

Measure Total Resource Cost The measure TRC calculates the net present value of energy and water savings that result from an investment in an efficiency technology or measure. The measure TRC is equal to its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy and equipment operating and maintenance (O&M) costs. This calculation includes, among others, the following inputs: the avoided natural gas, electricity and water supply costs, the life of the technology and the selected discount rate, which in this analysis has been set at 10%.

The measure TRC test is the primary determinant of whether a measure is included in the economic potential forecast.

Milestone Years The Base Year is the calendar year 2007, and the milestone years are defined at five-year increments: 2012 and 2017.

[5] A Glossary is provided in Section 9.

Economic Potential Forecast

The Economic Potential Forecast is the level of natural consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost effective from Union's perspective. All the energy-efficiency technologies and measures that have a positive measure TRC are incorporated into the Economic Potential Forecast. These technologies and measures are applied at either natural stock turnover rates or at designated years for immediate application.

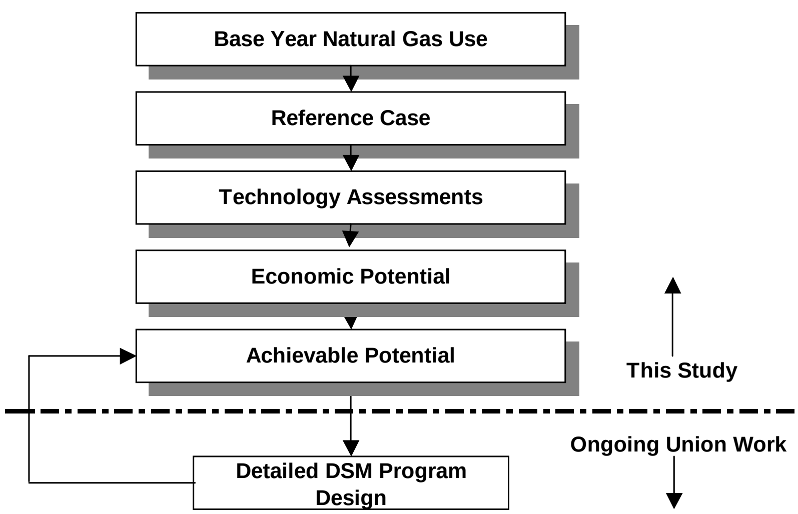
Achievable Potential

The Achievable Potential is the proportion of the natural gas savings identified in the Economic Potential Forecast that could realistically be achieved, given no other market barriers, within the study period. Achievable Potential recognizes that it is difficult to induce customers to purchase and install all of the efficiency technologies that meet the criteria defined by the Economic Potential Forecast.

1.4 APPROACH

To meet the objectives outlined above, the study was conducted within an iterative process that involved a number of well-defined steps. At the completion of each step, the client reviewed the results and, as applicable, revisions were identified and incorporated into the interim results. The study then progressed to the next step. A summary of the steps is presented in Exhibit 1.2 and briefly discussed below.

Exhibit 1.2: Major Study Steps



Step 1: Develop Profile of Base Year Natural Gas Use

- Compile and analyze available data on Union's existing industrial facilities including customer billing data and information from customer surveys, etc.
- Divide industrial facilities into Union service regions and sub sectors and compile actual Union billing data for each
- Develop detailed technical profiles of natural gas use in the existing facilities within each sub sector

- Undertake computer simulations of energy use in the existing facilities, generate model results by sub sector, end use and service region, and compare these with actual billing data and data from Marbek's in-house database
- Calibrate model results using actual Union billing data
- The output of Step 1 forms Section 2 of this report.

Step 2: Develop Reference Case Forecast for the Study period

- Compile and analyze data on forecast growth in output for each major sub sector
- Compile data on "natural" changes in equipment efficiency levels and/or practices. (For definition of "natural conservation," see above under Section 1.3: "Reference Case Forecast")
- Define sector model inputs and create forecasts of energy use for each of the milestone years
- Compare sector model results with Union's forecast for the period
- The output of Step 2 forms Section 3 of this report.

Step 3: Develop and Assess Energy-efficiency Upgrade Options

- Develop list of energy-efficiency measures in consultation with Union
- Compile detailed cost and performance data for each measure
- Assess the energy and economic impacts of implementing the energy-efficiency upgrade options in place of the baseline technologies employed in the Reference Case
- Determine the measure TRC for each upgrade option
- The output of this task forms Section 4 of this report.

Step 4: Estimate Economic Energy Savings Potential

- Compile utility economic data on the forecast cost of new natural gas supply
- Screen the identified energy-efficiency upgrade options from Step 3 against the utility economic data
- Identify the combinations of energy-efficiency upgrade options and sub sectors where the measure TRC is positive
- Apply the economically attractive efficiency measures from Step 3 within the energy use simulation model developed previously for each industrial sub sector
- Compare the energy consumption levels when all economic efficiency measures are used with the Reference Case consumption levels and calculate the energy savings
- The output of this task forms Section 5 of this report.

Step 5: Estimate Achievable Energy Savings Potential

- "Bundle" the energy saving opportunities identified in the Economic Potential Forecast into a set of Actions
- Create "Action Profiles" for each of the identified Actions that provide a "high-level" rationale and direction, including target technologies and sub markets as well as key barriers and a broad intervention strategy
- Review historical achievable program results and prepare preliminary Action Assessment Worksheets
- Conduct Achievable Potential workshops involving utility and consultant team personnel, selected trade allies and technology and market experts to reach general agreement on a range of achievable potential based on different funding scenarios
- The output of this task forms Section 6 of this report.

1.5 ANALYTICAL MODELS

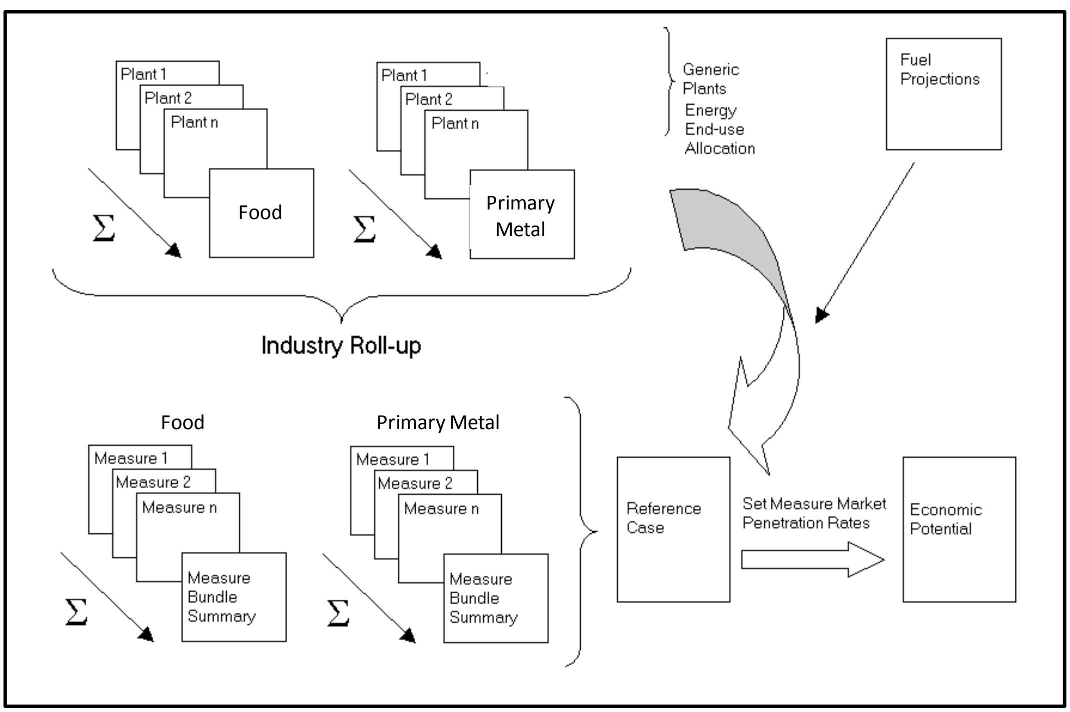
The analysis of the Industrial sector employed Marbek's Industrial Energy Efficiency Model (IEEM)[6]. The model is built in a spreadsheet format and is organized by major industrial sub sector and major end use. The sub sectors and end uses are described in detail in Section 2.

The model addresses each sub sector by defining a "generic" plant for the sub sector as a whole. Exhibit 1.3 illustrates how the model combines sub sector, end use, efficiency measures and fuel share data to generate the energy use forecasts used in the study.

The generic plant construct within the model is used to define an energy consumption profile representative of a "typical" or archetype plant within a given industry sub sector (or a specific type of plant within a given sub sector if there are substantial process differences). The generic plant is a composite of energy use patterns, energy intensities and consumption levels within the particular target sub sector. The candidate energy management measures are applied to the generic plant to model energy savings potential.

Marbek's existing stock of generic industrial plants was used as a starting point for the analysis. The model was customized to the specific Union industrial customer base, based on reports provided by Union, a literature research and the study team's extensive work in Ontario's industrial facilities.

Exhibit 1.3: Industry Energy Efficiency Model (IEEM) Diagram



6 All input assumptions that are not otherwise referenced are from the Marbek internal database.

1.6 THIS REPORT

This report addresses the Industrial sector and provides a summary of the results to date. This initial report is presented in the following sections.

- Section 2 presents a profile of Base Year natural gas use in Union's Service Area, including a discussion of the major steps involved and the data sources that were employed.
- Section 3 presents the Industrial sector Reference Case for the study period 2007 to 2017.
- Section 4 provides a financial and economic assessment of the identified Industrial sector energy-efficiency measures.
- Section 5 presents the Industrial sector Economic Potential Forecast for the study period 2007 to 2017.
- Section 6 presents the estimated range of Achievable Potential for natural gas savings, under differing scenarios, for the study period 2007 to 2017.
- Section 7 presents high level conclusions.
- Section 8 presents a listing of major references.

2. BASE YEAR NATURAL GAS USE

2.1 INTRODUCTION

This section presents a description of natural gas use in Union's Industrial sector in the Base Year of 2007. Drawing on the best available data, this section presents total natural gas consumption in Union's Industrial sector, together with an estimate of how that consumption is distributed by service region, sub sector, end use and technology.

The remainder of this section outlines the steps involved in preparing the profile of Base Year natural gas use and presents a summary of the results. The discussion is organized into the following subsections:

- Segmentation of Industrial sector facilities
- Union industrial Base Year sales data
- End-use profile of natural gas consumption
- Summary of Base Year model results.

2.2 SEGMENTATION OF INDUSTRIAL FACILITIES

The first step in the Base Year calibration required segmenting the industrial accounts into sub sectors. To facilitate the analysis of energy-efficiency options in later stages of this analysis, the accounts were grouped such that the natural gas using processes and technologies were approximately similar within each sub sector.

A summary of the Industrial sub sectors used in this study is provided in Exhibit 2.1. Exhibit 2.1 also shows the Union sub sector customer groups that are included in each of the defined Industrial sub sectors.

It was also agreed that the primary study focus would be on the large, contract sub sectors (see Section 2.2.2 below for definition). The modelled output from these sub sectors was used to derive results for the remaining sub sectors defined in Exhibit 2.1. The derived results were based on the proportional natural gas consumption by each sub sector.

Exhibit 2.1: Industrial Sub Sectors and Union Sub sector Descriptions

Study Sub sectors	Union Sub sectors Included
Contract Primary Metal	Steel & Non-Ferrous Smelting (Contract)
Contract Paper	Pulp & Paper (Contract)
Contract Transportation and Machinery	Auto (Contract)
Other Transportation and Machinery	Heavy Mfg/Assembly Light Mfg/Assembly
Contract Chemical	Chemical (Contract)
Other Chemical	Chemical/Petro Processing
Contract Food and Beverage	Food & Beverage (Contract)
Other Food and Beverage	Food & Beverage Processing
Contract Mining (Except oil and gas)	Mining (Contract)
Other Mining (Except oil and gas)	Industrial Mines Aggregate Processing / Mfg.
Contract Non-Metallic Mineral	Glass (Contract) Cement (Contract) Lime (Contract) Building Products (Contract)
Contract Petroleum Refineries	Refinery (Contract)
Miscellaneous Industrial	Greenhouse (Contract) Miscellaneous (Contract) Recycling (Contract) Industrial Building / Other Metal Fabrication (Contract) Textiles and Apparel Wood & Paper Mfg (small / medium) Marketers / Producers (Contract) Asphalt (Contract) Smelting / Casting / Refining SME Agriculture (Contract) Farm / Agriculture Building Farm / Agriculture Other Farm / Agriculture Pump Farm / Agriculture Drying

Selected additional information elaborating on the definition of the sub sectors shown in Exhibit 2.1, such as NAICS classification and definition of "contract" sub sectors, is provided below.

2.2.1 Sub Sector Classification

Classification of the study sub sectors is based on the North American Industry Classification System (NAICS). The eight core sub sectors modelled in the study and their associated NAICS codes and descriptions are summarized in Exhibit 2.2.

Exhibit 2.2: Industrial Sub Sectors and Associated NAICS Codes and Descriptions

NAICS	NAICS Description
331	Primary Metal Manufacturing
322	Paper Manufacturing
336 & 333	Transportation Equipment Manufacturing & Machinery Manufacturing
325	Chemical Manufacturing
311 & 312	Food Manufacturing & Beverage and Tobacco Product Manufacturing
212	Mining (except Oil and Gas)
32411	Petroleum Refineries
327	Non-metallic Mineral Product Manufacturing

2.2.2 Contract Sub Sectors

Union divides its industrial customers into large volume users and small and medium volume users. The large volume users are referred to as “Contract” market customers by Union; the small and medium volume users are referred to as “Other” in this study. For example, “Contract Chemical” refers to the all the large volume users (referred to by Union as Contract market) in the NAICS sub sector 325 – Chemical Manufacturing; the “Other Chemical” sub sector refers to all the small and medium volume customers in the same NAICS sub sector.

2.2.3 Electric Power Generation

The Electric Power Generation sub sector includes the Union Gas sub sectors of Hydro (in the Contract market), and Independent Power Producers. This sub sector is not included in the current scope of the assessment, and Union Gas will assess the energy efficiency potential in this sector separately, or as part of an extension of the study scope.

2.3 UNION CUSTOMER BASE YEAR SALES DATA

Once agreement was reached on the selection and definition of the Industrial sub sectors shown in Exhibit 2.1, Union compiled a summary of its total 2007 customer sales, segmented into the selected sub sectors. The original billing data included natural gas consumption as feedstock and for on-site cogeneration. Sub sectors for which cogeneration and/or feedstock comprise a large portion of total gas consumption include:[7]

- Chemical Manufacturing (32%)
- Petroleum Refining (55%)
- Transportation Equipment and Machinery Manufacturing (5%)
- Food and Beverage Manufacturing (37%).

As natural gas use for cogeneration and feedstock are outside the scope of this study, these consumption volumes were subtracted from the sub sector totals addressed by this study.[8] The resulting Base Year natural gas consumption in each service area by sub sector and total Industrial sector is summarised in Exhibit 2.3.

Exhibit 2.3: Base Year Industrial Natural Gas Use, by Service Region

Sub Sector	Gas Consumption (1000 m^3)			Percentage of Total (%)
	Northern	Southern	Total	
Contract Primary Metal	398,032	980,383	1,378,415	25%
Contract Chemical	256,247	749,587	1,005,834	18%
Other Chemical	2,310	34,720	37,030	0.7%
Contract Paper	537,762	29,456	567,218	10%
Contract Transportation and Machinery	10,593	380,739	391,332	7%
Other Transportation and Machinery	1,411	147,811	149,223	3%
Contract Petroleum Refineries	-	375,989	375,989	7%
Contract Mining	307,752	12,365	320,117	6%
Other Mining	-	25	25	0.0004%
Contract Food and Beverage	39,603	212,168	251,771	5%
Other Food and Beverage	2,527	53,266	55,793	1%
Contract Non-Metallic Mineral	21,239	258,672	279,911	5%
Miscellaneous Industrial	76,363	576,418	652,781	12%
Total	1,653,839	3,811,599	5,465,438	100%
Percentage	30%	70%		

[7] An assessment of data obtained at the completion of this study indicated that up to about 42% of the Base Year natural gas consumption in the Contract Primary Metal sub sector could be considered as feedstock. It was not feasible to include the data in the study at this late stage of the study. The implication is that the energy efficiency potential in the Contract Primary Metal sub sector might be overstated.

[8] It was assumed that all cogeneration occurs within the Contract sub sectors.

2.4 END-USE PROFILE OF NATURAL GAS CONSUMPTION

The next step involved the development of a profile that shows how the natural gas use presented in Exhibit 2.3 is distributed among the major end uses that were defined for this study, namely:

- Hot Water Systems
- Boilers and Steam Systems
- Process Direct Heat
- Other Process
- HVAC.

The following discussion provides a brief description of each end use and, to the extent that data permit, provides highlights on the Base Year conditions.

2.4.1 Hot Water Systems

This end use includes all hot water boilers, water heaters and hot water distribution systems. The boilers/heaters and hot water distribution system are considered as one end use because any energy-efficiency measures applied to the distribution system will result in a reduction in gas consumption at the boilers/heaters. For boiler population and vintage see the discussion below under the boilers and steam system end use.

2.4.2 Boiler steam systems

Similar to the hot water systems, this end use includes all steam boilers, steam distribution systems and condensate return systems. The boilers and steam distribution systems are considered as one end use because any energy-efficiency measures that are applied to the distribution system will result in a reduction in gas consumption at the boilers.

In 2005, the Union Service Area included about 2,080 boilers in steam plants in the Industrial and institutional sectors.[9] Assuming at least 70% of the boilers are in the Industrial sector, the estimated population of large, steam boilers in the Union Service Area is approximately 1,500 units.

Although detailed data on the distribution of Ontario industrial boilers by size is not available, the results of similar work in the U.S. is expected to be at least indicative of conditions within Ontario's Industrial sector. Exhibit 2.4 provides a profile of the U.S. steam and hot water boiler population by size.

[9] Griffin, B. *The Enbridge "Steam Saver" Program – Steam Boiler Plant Efficiency-Update to Year End, 2005*. 2006. www.steamingahead.org/library/enbridge05.pdf. (Latest publically available report).

Exhibit 2.4: Profile of Size Distribution of Boilers in U.S.[10]

Boiler Size		Percentage of Total
[BHP]	[MMBTU/hr]	
<300	<10	55%
300-1500	10-50	29%
1500-3000	50-100	8%
3000-7500	100-250	5%
>7500	>250	3%

Although detailed data on the age of Ontario's steam boilers is not available, the same U.S. data noted above indicates that the vintage profile for boilers larger than 300 BHP is that 7% are less than 10 years old and 76% are more than 30 years old. Based on the age of Ontario's industry it is expected that a similar vintage profile would be applicable to Ontario's heavy industry, such as Primary Metal, Chemical, Paper, Petroleum Refineries and Mining, while the lighter manufacturing industry in Ontario's profile will have a larger percentage of newer boilers. Larger boilers tend to be primarily steam boilers, while smaller boilers include a larger share of hot water boilers.

2.4.3 Process Direct Heat

This end use includes the processes where natural gas is directly applied to heat product, unlike the steam and hot water system end uses where the heat energy from natural gas combustion is transferred indirectly through a medium, such as steam or water. Specific technologies included in the process direct heat end use are ovens, dryers, kilns and furnaces.

Similar to the boiler population, a large portion of the process direct end-use equipment population is relatively old. This is especially true for large equipment in the large, energy-intensive industrial facilities

2.4.4 Other Process

This end use includes all other process specific technologies, which are sub sector specific, and include, for example, chemical evaporators.

2.4.5 Heating, Ventilation and Air Conditioning (HVAC)

The heating, ventilation and air conditioning (HVAC) end use includes technologies where natural gas is used in HVAC processes for both comfort, such as space heating during winter months, and process, such as ventilation of paint booths or welding booths, and air supply for greenhouses.

[10] Energy and Environmental Analysis, Inc. *Characterization of the U.S. Industrial Commercial Boiler Population*, Oakridge National Laboratory, 2005.

2.4.6 Data Sources

The Base Year end use profiles were developed based on an extensive literature review and the project team's experience in the sub sectors. More specifically, the distribution of natural gas use by end use within each sub sector was determined mainly with data from the following sources:

- CIEEDAC (provides annual national energy usage per sector for Canada)
- Office of Industrial Technology (reports end-use data for sectors in the U.S.)
- U.S. Department of Energy – Energy Efficiency and Renewable Energy (provides energy use profiles for energy-intensive industries for the U.S.)
- U.S. Manufacturing Energy Consumption Survey (reports annual energy usage per end use for sectors in the U.S., U.S. Department of Energy). Data that was primarily U.S. plant specific was adjusted for Ontario based on the seasonal gas usage of Union customers.

2.5 SUMMARY OF BASE YEAR MODEL RESULTS

This sub section provides a summary of results of the Base Year model. The results are presented in Exhibits 2.5 to 2.7. The exhibits show the distribution of Base Year natural gas use by sub sector and end use for the total Union Service Area in volumetric and percentage units.

The detailed breakdown of the Base Year natural gas consumption by service region is presented in Appendix A.

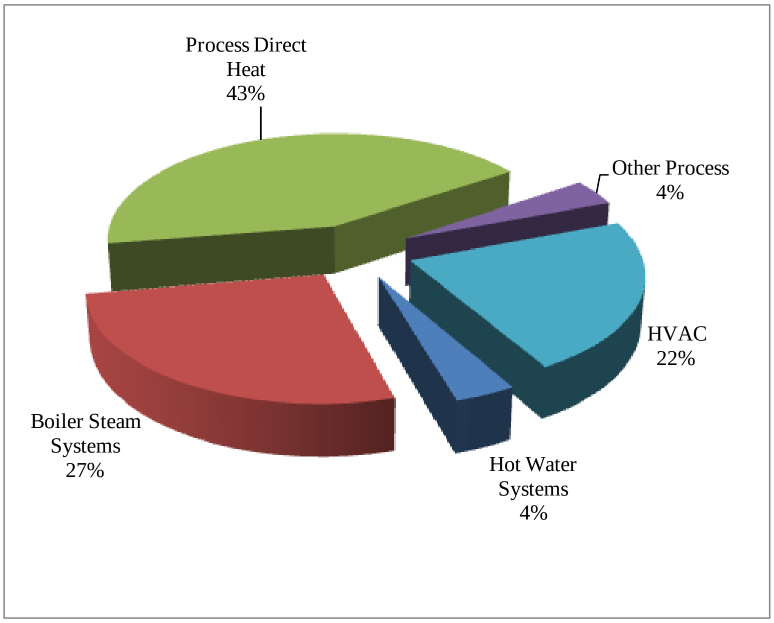
Exhibit 2.5: Base Year (2007) Natural Gas Consumption by Sub Sector and End Use for the Total Service Area (1000 of m^3/yr.)

Sub Sector	End Use						
	Hot Water Systems	Boiler Steam Systems	Process Direct Heat	Other Process	HVAC	Total	
Contract Primary Metal	27,568	161,964	963,099	31,428	194,357	1,378,415	25%
Contract Chemical	20,117	408,369	331,925	74,222	171,201	1,005,834	18%
Other Chemical	741	15,034	12,220	2,732	6,303	37,030	0.7%
Contract Paper	11,344	353,887	107,431	10,380	84,175	567,218	10%
Contract Transportation and Machinery	7,827	91,046	117,313	15,868	159,278	391,332	7%
Other Transportation and Machinery	2,984	34,718	44,734	6,051	60,736	149,223	3%
Contract Petroleum Refineries	7,520	72,251	253,607	6,738	35,873	375,989	7%
Contract Mining	64,023	80,029	112,041	16,006	48,017	320,117	6%
Other Mining	5	6	9	1	4	25	0.0004%
Contract Food and Beverage	20,142	120,397	69,212	15,585	26,436	251,771	5%
Other Food and Beverage	4,463	26,680	15,337	3,454	5,858	55,793	1%
Contract Non-Metallic Mineral	5,598	33,477	198,345	10,581	31,910	279,911	5%
Miscellaneous Industrial	33,945	75,984	127,031	17,690	398,131	652,781	12%
Total	206,277	1,473,842	2,352,303	210,736	1,222,280	5,465,438	
%	4%	27%	43%	4%	22%		100%

Exhibit 2.6: Base Year (2007) Natural Gas Consumption as Percentages by End Use and Sub Sector for the Total Service Area

Sub Sector	Total Consumption (1000 m^3)	End Use					
		Hot Water Systems	Boiler Steam Systems	Process Direct Heat	Other Process	HVAC	Total
Primary Metal	1,378,415	2%	12%	70%	2%	14%	100%
Chemical	1,042,864	2%	41%	33%	7%	17%	100%
Paper	567,218	2%	62%	19%	2%	15%	100%
Transportation and Machinery	540,554	2%	23%	30%	4%	41%	100%
Petroleum Refineries	375,989	2%	19%	67%	2%	10%	100%
Mining	320,141	20%	25%	35%	5%	15%	100%
Food and Beverage	307,563	8%	48%	27%	6%	11%	100%
Non-metallic Mineral	279,911	2%	12%	71%	4%	11%	100%
Miscellaneous Industry	652,781	5%	12%	19%	3%	61%	100%
Overall	5,465,438	4%	27%	43%	4%	22%	100%

Exhibit 2.7: Base Year (2007) Natural Gas Consumption by End Use for the Total Service Area (1000 of m^3/yr.)



2.5.1 Interpretation of Results

Selected highlights of the information presented in Exhibits 2.5 to 2.7 are presented below.

Sub Sectors

The total annual industrial natural gas consumption for the 2007 Base Year (exclusive of cogeneration and feedstock gas consumption) was 5,465 million m^3.

Approximately 53% of the total natural gas is consumed by three sub sectors: Contract Primary Metal, Contract Chemical and Contract Paper.

Total natural gas consumption by the Contract sub sectors account for 82% of the total Base Year gas consumption and is equal to 4,571 million m^3.

End Use

Direct process heating in ovens, dryers, kilns and furnaces accounts for the largest share (43%) of industrial natural gas use, followed by steam generation in boiler steam systems (27%) and HVAC (22%). Hot water (4%) and Other Processes (4%) account for the remaining natural gas consumption.

The subsectors accounting for the largest share of natural gas in the three major end uses are:

- Contract Chemical and Contract Paper, which accounts for 52% (762 million m^3) of gas use in the boiler steam system end use.
- Contract Primary Metal, which accounts for 43% (963 million m^3) of gas use in the process direct heat (which includes furnaces, kilns, dryers and ovens) end use.
- Miscellaneous Industrial, which accounts for 22% (398 million m^3) in the HVAC end use.

3. REFERENCE CASE FORECAST

3.1 INTRODUCTION

This section presents the Industrial sector Reference Case forecast for the study period 2007 to 2017. The Reference Case estimates the expected level of natural gas consumption that would occur over the study period in the absence of new Union DSM initiatives. The Reference Case, therefore, provides the point of comparison for the calculation of opportunities associated with each of the subsequent scenarios that are assessed within this study.

The discussion is presented within the following sub sections:

- Expected growth rates, by sub sector
- Summary of model results
- Interpretation of results.

3.2 EXPECTED GROWTH RATES, BY SUB SECTOR

The Reference Case is based on Union's load forecast, which is informed by data obtained directly from the large volume industrial users. This data provides an understanding of the expected industry changes during the study period, such as new plants or plant closures, process changes, projected production growth and changes to fuel shares. It also includes planned major energy-efficiency projects and, as a result, captures "natural conservation" impacts.

Union's load forecast and growth rates for each of the industry sub sectors were determined for the period 2007 to 2012. However, the Union forecast does not extend beyond 2012; consequently, in the absence of specific data, the 2007 to 2012 growth rates for each sub sector were held constant to the end of the study period. Exhibit 3.1 provides a summary of natural gas growth rates that are forecast for the sub sectors and service regions addressed by this study. To undertake the modeling for the total region a weighted average growth rate was determined for each sub sector, based on the proportional gas consumption by the Southern and Northern regions. Exhibit 3.1 presents the weighted average for the total service regions over the two milestone periods. The growth rates are used in the model to determine the Reference Case gas consumption by sub sector and milestone year.

As illustrated in Exhibit 3.1, industrial natural gas consumption is forecast to decrease by a sales-weighted average of about 0.13% from 2007 to 2012 for the total Union Service Area. As also illustrated in Exhibit 3.1, there is a significant regional difference in the expected rates. The rate of increase during the period 2012 to 2017 is estimated to be about 2.6%; this result incorporates the continuation of the 2007-2012 sub sector growth rates in combination with the forecast consumption volumes in each service region.

Exhibit 3.1: Reference Case Forecast Natural Gas Consumption Growth Rates for Milestone Periods Compared to Base Year 2007

Sub Sector	Milestone Percent Growth (2007 – 2012)		Weighted Avg. Percent Growth (2007-2012)	Weighted Avg. Percent Growth (2012-2017)
	Northern	Southern		
Primary Metal	13.3%	4.0%	6.7%	6.9%
Chemical	35.3%	1.5%	9.9%	11.8%
Paper	-27.9%	5.8%	-26.1%	-25.4%
Transportation and Machinery	4.9%	-15.5%	-15.1%	-15.0%
Petroleum Refineries	0.0%	4.3%	4.3%	4.3%
Mining	-0.4%	-21.8%	-1.2%	-1.0%
Food and Beverage	66.6%	-15.5%	-4.2%	4.1%
Non-metallic Mineral	20.9%	1.3%	2.8%	3.0%
Miscellaneous Industry	-49.5%	9.9%	3.0%	6.5%
Overall	-0.7%	0.1%	-0.13%	2.6%

3.3 "NATURAL" CHANGES AFFECTING NATURAL GAS CONSUMPTION

The Reference Case recognizes that, even in the absence of DSM market interventions, there will be "natural" changes[11] in natural gas consumption patterns over the study period. Specific impacts and trends that are applicable to the industrial end uses are discussed below according to:

- Regulation of industrial GHG emissions
- Changes affecting industrial end uses.

3.3.1 Regulation of Industrial GHG Emissions

The Federal government issued the final Regulatory Framework for Air Emissions in April 2007, which laid out the broad design of the regulations for industrial emissions of both greenhouse gases (GHG) and air pollutants.[12] Natural gas combustion contributes to GHG emissions and one can expect the regulation to impact natural gas consumption in the regulated sub sectors. Highlights are provided below related to affected sub sectors, reduction targets and timing.

❑ Sub Sectors

The regulatory framework for industrial GHG emissions proposes that the following sub sectors be covered by the regulations:

- Electricity generation produced by combustion
- Oil and gas (including oil sands, upstream oil and gas, natural gas pipelines and petroleum refining)

[11] "Natural changes" refer to those changes that are expected in the absence of any Union programming.

[12] Environment Canada. *Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions*, 2008, www.ec.gc.ca/doc/virage-corner/2008-03/541_eng.htm.

- Pulp and paper
- Iron and steel
- Iron ore pelletizing
- Smelting and refining (including base metals smelting, aluminum and alumina, and ilmenite (titanium) smelting)
- Cement
- Lime
- Potash
- Chemicals and fertilizer.

- ❑ Emission Reduction Targets

The proposed targets to be achieved by the Industrial sub sectors include:

- All covered Industrial sectors will be required to reduce their emissions intensity from 2006 levels by 18% by 2010, with 2% continuous improvement every year after that.
- The target will be applied at the facility, sector or corporate level, as determined after consultations with each sector.
- Fixed process emissions will receive a 0% target. The definition of fixed process emissions will be based on technical feasibility.
- To provide incentives to adopt the best available technologies for new facilities, whose first year of operation is 2004 or later, a target based on a cleaner fuel standard will be applied.
- There will be an incentive until 2018 for facilities to be built "carbon-capture ready."
- A special incentive will be provided through the target structure for high-efficiency cogeneration.

- ❑ Timing

The following expected timeframe to legislate the regulation is provided by Environment Canada:

- Draft regulation to be published in the *Canada Gazette* for public comment in fall 2008.
- Final regulations approved and published in *Canada Gazette* in fall 2009. Regulations to come into force on January 1, 2010.

- ❑ Summary & Implications for this Study

As illustrated by the above listing, most of the sub sectors addressed by this study will be affected by this regulation when it comes into effect. Moreover, the proposed regulation of GHG emissions from large industrial sources has the potential to have a significant impact on industrial natural gas consumption over the study period. However, at this point in time it is not possible to accurately predict the eventual direction or magnitude of GHG regulation. On the one hand, it is expected that regulated sub sectors would increase their overall investment in energy efficiency; on the other hand, GHG emission regulations would also promote a shift away from GHG intensive fuels, such as oil and coal, to less GHG intensive fuels, such as natural gas.

3.3.2 Other Influences Affecting Industrial End Uses

In addition to the potential broad impacts from the proposed regulation of industrial emissions of GHG and other air pollutants, other influences related to the age of the installed equipment and naturally occurring improvements in equipment efficiency are also expected to affect natural gas use over the study period. To the extent that data permit, a brief discussion of key influences is presented below for each of the major end uses addressed by this study, namely:

- Boiler Steam and Hot Water Systems
- Process Direct Heat
- Process Specific
- HVAC
- Plant and System Integration Measures.

❑ Boiler Steam and Hot Water Systems

As noted previously in Section 2, Ontario industry has a large population of boilers at a very advanced age; consequently, it is expected that many of the boilers will be replaced or decommissioned during the next decade. Replacing these aged boilers with new ones will result in reduced energy use, due to the advances in boiler efficiency that have occurred over the past 40 years. However, in the absence of "drivers" such as GHG emission regulation, or further DSM support, it is expected that efficiency improvements will continue at a modest pace. More specifically:

- Data applicable to programs offered in Ontario provides insight in the participation rates of boiler and steam system energy-efficiency measures in the Industrial sector when supported by a program.[13] According to a 2006 analysis, only 32% of identified energy-efficiency projects with a payback period of less than 1.2 years were implemented. In the absence of a DSM program one would expect a significantly lower participation rate of the energy-efficiency measures.

- Most of the opportunities identified by energy assessments in Ontario programs include: economizers and heat recovery, combustion improvements, capital projects (such as new boilers) and steam distribution and condensate return improvements. These are generally the first type of projects to be addressed and one can expect more natural change associated with the measures compared to other measures, such as insulation and chemical boiler water treatment.

- A large portion of the steam and hot water systems would be of the same vintage as the boilers. Lack of maintenance and poorly designed systems provide a significant opportunity. Without DSM intervention, one can expect very limited natural change due to various barriers, such as a lack of internal technical resources and expertise, organizational changes, lack of an energy management structure, etc.

[13] Griffin, B. *The Enbridge "Steam Saver" Program – Steam Boiler Plant Efficiency-Update to Year End, 2005*. 2006. www.steamingahead.org/library/enbridge05.pdf (Latest publically available report).

- Process Direct Heat (Furnaces, Kilns, Ovens and Dryers)

Similar to the boiler population, a large portion of the process direct end-use equipment population, which includes furnaces, kilns, ovens and dryers, is relatively old. This is especially true for large equipment in the large, energy-intensive industrial facilities. Similar observations and trends discussed above for boiler systems are applicable to process direct heat, and include:

- Large population of relatively old stock. Replacement of equipment with more efficient equipment at the end of life would increase natural change in gas consumption. Experience in the Industrial sector has indicated that replacement of process direct heating equipment occurs at a much slower pace compared to boilers.

- Limited implementation of energy-efficiency measures in the absence of a DSM program. With increased natural gas prices and price volatility, the focus on energy-efficiency measures is expected to increase.

- Implementation of energy-efficiency measures is constrained by a number of barriers, such as lack of internal resources and technical expertise, organizational changes, lack of an energy management structure, etc.

- Other Process

It is expected that the proposed Federal GHG emission regulation (see 3.3.1 above) will influence natural gas consumption and increase energy efficiency in regulated sub sectors.

As described above, similar observations in terms of vintage and trends are applicable to the process specific equipment for the process direct end use in Section 3.3.2.

- HVAC

Currently, unitary air conditioning units (19 kW to 73 kW) sold in Canada are regulated by Canada's Energy Efficiency Regulations and are required to meet minimum efficiency levels as specified in the Canadian Standards Association's CSA C746-98, Performance Standard for Rating Large Air Conditioners and Heat Pumps. (These regulations are currently under review.) In accordance with commitments made under the Montreal Protocol, the use of HCFC-22 as the refrigerant in unitary air-conditioning units will be phased out in new equipment by 2010.[14]

Replacing older air conditioning units at the end of life with newer more efficient models will result in increased energy efficiency. Due to the smaller sizes and lower capital cost, small- and medium-size HVAC units tend to be replaced more frequently when compared with boilers and other large thermal equipment. Large HVAC units are much more

[14] Natural Resources Canada. Office of Energy Efficiency. *High-Efficiency Unitary Air-Conditioning Units (19 to 73 kW),* 2006. http://oee.rncan.gc.ca/industrial/equipment/heating/index.cfm?attr=24.

expensive to replace and, therefore, a large percentage of the existing units are of an older vintage and may require replacement during the next 10 years.

- Plant and System Integration Measures

Plant or system measures are generally not executed by facilities, unless they are supported by a DSM program. Many large, energy-intensive industrial facilities already have some form of integrated control systems and sub-metering. To upgrade these systems to more modern and efficient systems can be expensive and the systems generally need to be installed during a shut down. The implementation of these measures is expected to be limited in the absence of a DSM program.

3.4 SUMMARY OF MODEL RESULTS

This section presents a summary of the model results in the following exhibits:

- Exhibit 3.2 presents a summary of the results for the total Union Service Area, by milestone year and service region.

- Exhibits 3.3 and 3.4 present the results for the total service region, by end use and milestone year.

A detailed breakdown of the Reference Case results by service region is presented in Appendix B.

Exhibit 3.2: Reference Case Forecast Natural Gas Consumption by Milestone Year ($1000\ m^3$)

Sub Sector	Contract / SME		Northern Region			Southern Region			All Regions		
	% North	% South	2007	2012	2017	2007	2012	2017	2007	2012	2017
Contract Primary Metal	100%	100%	398,032	450,983	510,978	980,383	1,020,039	1,061,300	1,378,415	1,471,022	1,572,278
Contract Chemical	99%	96%	256,247	346,763	469,253	749,587	761,091	772,771	1,005,834	1,107,854	1,242,023
Other Chemical	1%	4%	2,310	3,126	4,230	34,720	35,253	35,794	37,030	38,379	40,024
Contract Paper	100%	100%	537,762	387,867	279,754	29,456	31,156	32,954	567,218	419,023	312,708
Contract Transportation and Machinery	88%	72%	10,593	11,107	11,646	380,739	321,547	271,557	391,332	332,653	283,202
Other Transportation and Machinery	12%	28%	1,411	1,480	1,552	147,811	124,831	105,424	149,223	126,311	106,976
Contract Petroleum Refineries	100%	100%	-	-	-	375,989	392,187	409,082	375,989	392,187	409,082
Contract Mining	100%	100%	307,752	306,571	305,394	12,365	9,671	7,564	320,117	316,242	312,958
Other Mining	0%	0.20%	-	-	-	25	19	15	25	19	15
Contract Food and Beverage	94%	80%	39,603	65,980	109,927	212,168	179,350	151,608	251,771	245,330	261,535
Other Food and Beverage	6%	20%	2,527	4,210	7,014	53,266	45,027	38,062	55,793	49,236	45,076
Contract Non-Metallic Mineral	100%	100%	21,239	25,670	31,026	258,672	261,940	265,249	279,911	287,610	296,275
Miscellaneous Industrial	100%	100%	76,363	38,563	19,475	576,418	633,692	696,656	652,781	672,255	716,131
Total			1,653,839	1,642,320	1,750,247	3,811,599	3,815,802	3,848,036	5,465,438	5,458,123	5,598,284

Selected highlights of the information presented in Exhibits 3.2 relevant to service region:

- Over the 10-year Reference Case period, natural gas consumption in the Southern service region is expected to increase by 36 million m^3/yr. (1.0%), while the Northern service region's gas consumption is expected to increase by 96 million m^3/year (5.8%) relative to the Base Year.

- Growth in natural gas usage in the Southern service region is driven mainly by the Contract Primary Metal and Miscellaneous Industrial sub sectors. Most of the reduction in natural gas consumption in this service region can be ascribed to the Transportation and Machinery (both Contract and Other) and Food and Beverage (both Contract and Other) sub sectors.

- Growth in natural gas usage in the Northern service region is driven mainly by the Contract Primary Metal and Contract Chemical sub sectors. Most of the reduction in natural gas consumption in this service region can be ascribed to the Contract Paper sub sector.

Exhibit 3.3: Reference Case Forecast Natural Gas Consumption by End Use for Milestone Year 2012 – Total Service Region (1000 m^3)

Sub Sector	End Use						
	Hot Water Systems	Boiler Steam Systems	Process Direct Heat	Other Process	HVAC	Total	
Contract Primary Metal	29,420	172,845	1,027,803	33,539	207,414	1,471,022	27%
Contract Chemical	22,157	449,789	365,592	81,750	188,566	1,107,854	20%
Other Chemical	768	15,582	12,665	2,832	6,532	38,379	0.70%
Contract Paper	8,380	261,429	79,363	7,668	62,183	419,023	8%
Contract Transportation and Machinery	6,653	77,394	99,722	13,489	135,395	332,653	6.09%
Other Transportation and Machinery	2,526	29,387	37,865	5,122	51,411	126,311	2.31%
Contract Petroleum Refineries	7,844	75,363	264,532	7,029	37,419	392,187	7%
Contract Mining	63,248	79,060	110,685	15,812	47,436	316,242	6%
Other Mining	4	5	7	1	3	19	0%
Contract Food and Beverage	19,626	117,317	67,441	15,186	25,760	245,330	4.5%
Other Food and Beverage	3,939	23,545	13,535	3,048	5,170	49,236	0.90%
Contract Non-Metallic Mineral	5,752	34,398	203,801	10,872	32,788	287,610	5.3%
Miscellaneous Industrial	34,957	78,251	130,821	18,218	410,008	672,255	12.3%
Total	205,276	1,414,365	2,413,832	214,566	1,210,085	5,458,123	100%
%	4%	26%	44%	4%	22%		

Exhibit 3.4: Reference Case Forecast Natural Gas Consumption by End Use for Milestone Year 2017 – Total Service Region (1000 m^3)

Sub Sector	End Use						
	Hot Water Systems	Boiler Steam Systems	Process Direct Heat	Other Process	HVAC	Total	
Contract Primary Metal	31,446	184,743	1,098,551	35,848	221,691	1,572,278	28%
Contract Chemical	24,840	504,261	409,868	91,651	211,403	1,242,023	22%
Other Chemical	800	16,250	13,208	2,953	6,812	40,024	0.71%
Contract Paper	6,254	195,099	59,227	5,723	46,406	312,708	6%
Contract Transportation and Machinery	5,664	65,889	84,898	11,483	115,268	283,202	5.06%
Other Transportation and Machinery	2,140	24,889	32,069	4,338	43,541	106,976	1.91%
Contract Petroleum Refineries	8,182	78,610	275,928	7,332	39,031	409,082	7%
Contract Mining	62,592	78,239	109,535	15,648	46,944	312,958	6%
Other Mining	3	4	5	1	2	15	0%
Contract Food and Beverage	20,923	125,066	71,896	16,189	27,461	261,535	4.7%
Other Food and Beverage	3,606	21,555	12,391	2,790	4,733	45,076	0.81%
Contract Non-Metallic Mineral	5,926	35,435	209,941	11,199	33,775	296,275	5.3%
Miscellaneous Industrial	37,239	83,358	139,359	19,407	436,768	716,131	12.8%
Total	209,614	1,413,397	2,516,876	224,562	1,233,836	5,598,284	100%
%	4%	25%	45%	4%	22%		

Selected highlights of the information presented in Exhibits 3.3 and 3.4 are presented below.

Sub Sectors

- Overall, the results of the Reference Case forecast show that natural gas use increases by about 2.4%, or 133 million m^3/yr., from 2007 to 2017.

- A significant increase in annual natural gas consumption occurs in the Contract Primary Metal and Contract Chemical sub sectors, which increase respectively by 194 million m^3/yr. and 236 million m^3/yr. from 2007 to 2017. Other sub sectors that show an increase in natural gas consumption from 2007 to 2017 are the Other Chemical, Contract Petroleum Refineries, Contract Food and Beverage, Contract Non-metallic Mineral and Miscellaneous Industrial sub sectors.

- The most significant decrease in annual gas consumption during the period 2007 to 2017 occurs in the Contract Paper (reduction of 254 million m^3/yr.) and Contract Transportation and Machinery (108 million m^3/yr.) sub sectors.

End Use

- In 2007, direct process heating in ovens, dryers, kilns and furnaces accounted for the largest share (43%) of industrial natural gas use, and this share is increased to 45% in 2017; boiler steam systems' share of 27% in 2007 decreases to 25% in 2017, while the share of gas consumption by the other end uses remains relatively unchanged.

4. ENERGY-EFFICIENCY MEASURES

4.1 INTRODUCTION

This section identifies and assesses the financial and economic attractiveness of the selected energy-efficiency measures for the Industrial sector. The discussion is organized and presented as follows:

- Methodology
- Summary of energy-efficiency results
- Description of energy-efficiency technologies and measures.

4.2 METHODOLOGY

The following steps were employed to assess the energy-efficiency measures:

- Select candidate energy-efficiency measures
- Establish technical performance for each measure within a range of applicable load sizes and/or service region conditions (e.g., degree days)
- Establish the capital, installation and equipment operating costs for each measure
- Calculate the simple payback from the customer's perspective
- Calculate the measure TRC
- Calculate the benefit/cost ratio.

A brief discussion of each step is outlined below.

Step 1: Select Candidate Measures

The candidate measures were selected in close collaboration with Union personnel based on a combination of a literature review and the previous experience of both the consultants and Union personnel. The selected measures are considered to be technically proven and commercially available, even if only at an early stage of market entry. Technology costs, which will be addressed in this section, were not a factor in this initial selection of candidate technologies.

Step 2: Establish Technical Performance

Marbek's in-house database of measures formed the basis for the performance characteristics of the measures. The database was developed from secondary sources and input from specialists in the industrial sector. The database has been used and reviewed in many studies. The database information was updated for existing and new measures from available secondary sources, including the experience and on-going research work of study team members and from equipment suppliers. References are provided for performance characteristics where specific sources are relevant, while non-referenced performance characteristics are from the Marbek database.

Step 3: Establish Capital, Installation and Operating Costs for Each Measure

Information on the cost of implementing each measure was also compiled from secondary sources, including the experience and on-going research work of study team members. As applicable, both the incremental and full cost of each measure was estimated. Marbek's database of measures was used as the basis and was updated for this study. References are provided for costs where specific sources are relevant, while non-referenced costs are from the Marbek database.

The incremental cost is applicable when a measure is installed in a new facility, or at the end of its useful life in an existing facility. In this case, incremental cost is defined as the difference between the energy-efficiency measure and the "baseline" technology. The full cost is applicable when an operating piece of equipment is replaced with a more efficient model prior to the end of its useful life.

In both cases, the costs and savings are annualized, based on the number of years of equipment life and the discount rate. The discount rate in this study is 10% and is based on data provided by Union, which is based on the latest load forecast input assumptions. The costs incorporate applicable changes in annual equipment-specific O&M costs. All costs are expressed in constant (2008) dollars.

Step 4: Calculate Simple Payback

The simple payback is generated to show the customer's financial perspective. Simple payback is "a measure of the length of time required for the cumulative savings from a project to recover its initial investment cost and other accrued costs, without taking into account the time value of money. The simple payback period is usually measured from the service date of the project."[15] The cost of the measure (incremental or full, as appropriate) is divided by the expected annual savings and the answer is given in years**.**

The following equation illustrates how this calculation is applied to a situation where an upgrade has a higher upfront cost than the baseline technology, but lower ongoing operating costs:

$$\text{Payback}_{\text{(years)}} = (\text{CostUpgr} - \text{CostBase})/(\text{AnnBase} - \text{AnnUpgr})$$

where:

CostUpgr	= initial capital cost of the upgrade measure ($)
CostBase	= initial capital cost of the baseline measure ($)
AnnUpgr	= ongoing operating cost of the upgrade ($/yr.)
AnnBase	= ongoing operating savings of the base ($/yr.)

[15] Fuller, S.K. & Petersen, S.R. National Institute of Standards Technology. *Life Cycle Costing Manual for the Federal Energy Management Program - Handbook 135*, 1996.

Step 5: Calculate the Measure Total Resource Cost (TRC)

The measure TRC calculates the net present value of energy and water savings that result from an investment in an efficiency measure. The measure TRC is equal to its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy and equipment O&M costs. This calculation includes, among others, the following inputs: the avoided natural gas, electricity and water supply costs, the life of the technology and the selected discount rate, which in this analysis has been set at 10%.

A technology or measure with a positive TRC value is included in subsequent phases of the analysis, which consists of the economic and achievable potential scenarios. A measure with a negative TRC value is not economically attractive and is therefore not included in subsequent stages of the analysis.

It should be noted that the measure TRC provides an initial screen of the technical options. Considerations such as program delivery costs, free riders and incentives are incorporated in later detailed program design stages, which are beyond the scope of this study.

Step 6: Calculate Benefit/Cost Ratio

The measure benefit/cost ratio indicates the relative attractiveness of the measures. It is defined as the net present value of benefits (i.e., energy and water savings over the measure's life) divided by the net present value of the incremental cost of the measure relative to the baseline technology (i.e., the equipment's capital and equipment-specific O&M costs) over its life. If a measure has a benefit/cost ratio in excess of 1.0, it means that the measure's benefits outweigh its costs. Such a measure would be included in subsequent stages of the analysis. A measure with a benefit/cost ratio that is well in excess of 1.0 (e.g., 3.0) is particularly attractive. Conversely, if a measure has a benefit/cost ratio of less than one, its costs outweigh its benefits. Such a measure would not be included in subsequent stages of the analysis.

4.2.1 Energy Costs

The financial and economic results presented in this section are based on the following:

- Avoided supply cost of natural gas
- Avoided supply cost of electricity and water
- Customer energy prices.

A brief discussion of each is provided below.

Avoided Supply Cost of Natural Gas

Natural gas avoided supply costs were provided by Union. The data provided were segmented into base load and weather-sensitive rates and their resulting net present values (NPVs). The rates were forecast for a 30-year timespan. The avoided supply costs also incorporate a GHG adder that accounts for carbon dioxide emissions resulting from natural gas consumption. A cost of $15/tonne CO_2e (per tonne of CO_2 equivalent) is employed until 2012 and the price is increased to $20 /tonne CO_2e starting in 2013.

An emissions coefficient of 0.001903 tonnes CO_2e/m^3 (1,903 g CO_2e/m^3) is used in this analysis.[16] The resulting avoided supply costs for natural gas are shown in Exhibit 4.1. The avoided supply cost is used in the TRC calculation (see description above under Section 4.2, Step 5).

Exhibit 4.1: Natural Gas – Avoided Supply Costs

Year	Base Load		Weather Sensitive	
	Gas Rates ($/m^3)	NPV ($/m^3)	Gas Rates ($/m^3)	NPV ($/m^3)
1	0.39898	0.39898	0.40143	0.40143
2	0.38189	0.74614	0.38823	0.75436
3	0.36510	1.04787	0.36231	1.05378
4	0.37148	1.32698	0.36864	1.33075
5	0.37799	1.58515	0.37510	1.58694
6	0.39425	1.82995	0.39130	1.82991
7	0.40101	2.05631	0.39800	2.05457
8	0.40790	2.26562	0.40483	2.26231
9	0.41492	2.45919	0.41179	2.45442
10	0.42207	2.63818	0.41889	2.63207
11	0.42936	2.80372	0.42611	2.79635
12	0.43678	2.95681	0.43348	2.94828
13	0.44435	3.09839	0.44098	3.08879
14	0.45206	3.22934	0.44863	3.21874
15	0.45992	3.35045	0.45642	3.33893
16	0.46793	3.46247	0.46436	3.45010
17	0.47608	3.56608	0.47245	3.55292
18	0.48440	3.66191	0.48070	3.64802
19	0.49287	3.75056	0.48910	3.73599
20	0.50150	3.83256	0.49766	3.81736
21	0.51030	3.90841	0.50639	3.89263
22	0.51927	3.97858	0.51528	3.96226
23	0.52840	4.04349	0.52433	4.02668
24	0.53771	4.10354	0.53357	4.08626
25	0.54719	4.15910	0.54297	4.14139
26	0.55686	4.21049	0.55256	4.19239
27	0.56671	4.25804	0.56232	4.23957
28	0.57674	4.30204	0.57228	4.28322
29	0.58697	4.34274	0.58242	4.32361
30	0.59739	4.38040	0.59275	4.36098

[16] Based on emission factors and Global Warming Potentials (GWPs) presented by Environment Canada in *Greenhouse Gas Sources and Sinks in Canada: National - Inventory Report 1990-2005*, p. 23 and 583, 2007.

Avoided Supply Cost of Electricity and Water

The study team undertook a review of the potential related water and electricity savings. The review concluded that these additional savings were minimal, relative to the magnitude of the natural gas savings and, consequently, would not affect the results presented in this section. The results presented in this section, therefore, refer only to natural gas savings.

Customer Energy Prices

The customer energy prices used in this analysis are presented in Exhibit 4.2. These values are used in the calculation of customer payback periods that are presented in later sections of this report. The natural gas prices shown are based on July 2008 rate schedules.

Exhibit 4.2: Customer Energy Prices

Service Region	Nat. Gas[17] ($\$/m^3$)
Northern Service Region	0.540
Southern Service Region	0.458

4.3 SUMMARY OF ENERGY-EFFICIENCY SCREENING RESULTS

A summary of the screening results for the energy-efficiency measures is presented in Exhibit 4.3. Due to the number of measures assessed for each sub sector, the results shown are for the measures applied to large technology in the Chemical sub sector. The results for the small- and medium-size technologies in the Chemical sub sector are presented in Appendix D, together with the measure TRC calculations for the remaining sub sectors. All the measures had a positive TRC in at least one sub sector for the large technology size. This means that all the measures passed the TRC screening and were included in the study. It should be noted that the following measures listed in Exhibits 1.1 and 4.4 were not assessed: first generation super boilers, computational fluid dynamic modelling, and process integration and pinch analysis. The reasons for the exclusion of these measures are described in the respective descriptions in Section 4.4.

The measures are grouped by end use and measures that apply to the total plant's natural gas use are grouped under the system end use. System end-use measures are those measures that do not apply to only one specific end use, such as boilers and steam systems, but apply to all end uses. For example, by controlling many end uses, an integrated control system would result in energy savings relative to the plant's total energy.

[17] Natural gas rates are approximate estimates based on Union rates (as of July 1, 2008) in each service region.

Exhibit 4.3: Summary of Measure TRC Screening Results - Example for Chemical Sub Sector, Medium Technology Energy-efficiency Options

End Use	Measure	Full/ Incremental	Net Measure TRC	Simple Payback Period (Years)	Benefit / Cost Ratio
System	Integrated control system	F	$ 7,895,530	0.1	45.3
	Sub-metering	F	$ 6,026,885	0.4	16.5
Boiler, Steam & Hot Water Systems	Economizer	F	$ 235,022	1.8	4.5
	Blowdown heat recovery	F	$ 88,954	3.4	2.4
	Boiler combustion air preheat	F	$ 131,864	4.4	1.7
	Process heat recovery to preheat make-up water	F	$ 294,079	3.0	2.8
	Condensing boiler	I	$ 688,500	0.8	11.0
	Direct contact hot water heaters	I	$ 804,906	0.1	N/A
	Boiler right sizing and load management	I	$ 809,906	0.1	N/A
	High-efficiency burners	F	$ 278,669	2.3	3.8
	Insulation	F	$ 285,489	0.9	7.3
	Advanced boiler controls	F	$ 110,952	3.3	2.3
	Blowdown control	F	$ 1,220	8.9	1.0
	Boiler water treatment	F	$ 22,412	3.2	1.8
	Boiler maintenance	F	$ 107,189	0.4	3.2
	Minimize deaerator vent losses	F	$ 76,954	4.2	2.0
	Condensate return	F	$ 46,251	6.1	1.4
	Steam trap survey and repair	F	$ 46,089	1.1	2.3
	Instantaneous steam generation	I	$ 936,275	0.6	17.6
Process Heating (Furnaces/ Kilns/ Ovens/ Dryers)	Exhaust gas heat recovery	F	$ 1,170,870	0.9	7.6
	High-efficiency burners and burner controls	F	$ 964,941	0.6	16.1
	Insulation	F	$ 398,957	0.8	8.9
	Advanced heating and process controls	F	$ 751,307	1.1	6.1
	High-efficiency ovens	I	$ 1,119,729	0.8	10.7
	High-efficiency dryers	I	$ 1,119,729	0.8	10.7
	High-efficiency kilns	I	$ 1,325,517	0.7	12.5
	High-efficiency furnaces	I	$ 1,325,517	0.7	12.5
	Air curtains	F	$ 1,436,897	0.6	14.5
Other Process	Pollution control measures	I	$ 772,269	1.1	4.0
	High-efficiency furnaces	F	$ 2,364,557	0.9	8.1
	Process heat recovery	F	$ 912,627	2.3	3.1
HVAC	Radiant heaters	F	$ 107,635	3.8	2.2
	Automated temperature control	F	$ 82,112	2.5	3.3
	Solar walls	F	-$ 71,311	14.2	0.6
	Ventilation & heat recovery optimization	F	$ 42,868	5.9	1.5
	Warehouse loading dock seals	F	-$ 107	6.2	1.0
	Air curtains	F	$ 11,037	5.1	1.5
	Air compressor heat recovery	F	$ 60,676	4.0	2.1
	Destratification fans	F	$ 31,511	4.2	2.0

4.4 DESCRIPTION OF ENERGY-EFFICIENCY TECHNOLOGIES AND MEASURES

This sub section provides a brief description of each of the energy-efficiency technologies and measures that are included in this study, as listed in Exhibit 4.4.

Exhibit 4.4: Energy-efficiency Technologies and Measures - Industrial Sector

System • Integrated control system • Sub-metering ***Boiler, Steam, and Hot Water Systems*** • Economizer • Blowdown heat recovery • Boiler combustion air preheat • Process heat recovery to preheat make-up water • Condensing boiler • First generation super boilers • Direct contact hot water heaters • Boiler right sizing and load management • High-efficiency burner • Insulation • Advanced boiler controls including air/fuel mix control • Blowdown control • Boiler water treatment • Boiler maintenance • Minimize deaerator vent losses • Condensate return • Steam trap survey and repair • Instantaneous steam generation	***Process Direct Heat (Furnaces / Kilns / Ovens / Dryers)*** • Exhaust gas heat recovery • High-efficiency burner and burner controls (including. oxy-gas direct impingement heating for steel annealing) • Insulation • Advanced heating and process control • High-efficiency ovens • High-efficiency dryers • High-efficiency kilns • High-efficiency furnaces • Air curtains ***Other Process*** • Pollution control measures • Computational fluid dynamic modeling • Hydrogen atmospheres for steel batch coil annealing • Process heat recovery • Process integration and pinch analysis ***HVAC*** • Radiant heaters • Automated temperature control • Solar walls • Ventilation heat recovery and optimization • Warehouse loading dock seals • Air curtains • Air compressor heat recovery • Destratification fans

The discussion is organized and presented in the following subsections:

- System
- Boiler, Steam, and Hot Water Systems
- Process Direct Heat (furnaces/kilns/ovens/dryers)
- Other Process
- HVAC.

Each option is discussed below, with a brief description of the technology, savings relative to the baseline, typical installed costs, applicability and co-benefits. The descriptions are measure specific and do not indicate the interactive effects of measures. For example, the typical measure savings indicates the savings if it is implemented as a stand-alone measure. When these measures are implemented together then these typical savings are not additive, but there is a cascading effect of reduced savings potential resulting from a reduced volume of gas usage subsequent to implementing a measure. The remaining potential to implement the measures is indicated and, unless a specific reference is provided, is based on the consulting team's experience.

4.4.1 System[18]

System-level measure bundles are efficiency upgrade options that span several energy end uses, and are therefore applied against the entire generic plant's energy consumption. Each measure bundle was modified as appropriate in term of savings, operating times, implementation costs, etc., to suit the generic plant type to which it was applied. The following measures were identified and assessed:

- Integrated control system
- Sub-metering.

Integrated Control System

Assumptions used for Analysis	
Sub Sectors	Medium and large industry
Typical Measure Size/Specification	Applied to medium / large facility
Typical Measure Costs	\$165,000 to \$500,000
Typical Measure Savings	8% in natural gas use[19]
Useful Measure Life	10 years

Traditionally, control systems have been implemented as separate entities, each with its own infrastructure, installer and service. This can result in control systems that, as a whole, are not utilized to their maximum potential. Applications of advanced, automated control and energy management systems in varying development stages can be found in all Industrial sectors. However, there is still a large potential to implement control and management systems, as more modern systems enter the market continuously.

Process control systems depend on information at many stages of the processes. The information of the sensors is used in control systems to adapt the process conditions, based on mathematical (rule-based) or neural networks and "fuzzy logic" models of the industrial process. Neural network-based control systems have successfully been used in the cement (kilns), food (baking), non-ferrous metals (alumina, zinc), pulp and paper (paper stock, lime kiln), petroleum refineries (process, site) and steel industries (EAFs, rolling mills). New energy management systems that use artificial intelligence, fuzzy logic (neural network), or rule-based systems mimic the "best" controller, using monitoring data and learning from previous experiences.

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[18] Unless otherwise noted, measure assumptions provided in this section are from Marbek's in-house database, which is compiled from a number of sources including previous and on-going studies, facility energy audits and surveys.

[19] Ernest, Orlando. Lawrence Berkley National Laboratory and the American Council for an Energy Efficient Economy (ACEEE). Emerging Energy-Efficient Industrial Technologies, 2000, report reference number: LBNL 46990.

Sub-Metering

Assumptions used for Analysis	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Applied to small / medium / large facility
Typical Measure Costs	$200,000 to $1,000,000
Typical Measure Savings	5%
Useful Measure Life	15 years

Sub-metering systems measure the amount of energy used by a plant and in particular certain portions of the plant where major utility loads are known. The use of sub-metering can be beneficial as part of a control system or an energy management plan. Well-placed sub-meters provide utility usage information for specific processes or plant areas, which can help in the identification of potential areas of improvement within. Data obtained from meters are only beneficial for demand-side management if it is interpreted and used in a DSM system or energy management framework, including monitoring and targeting strategies. Also, the closer the meter is to the end user, the more likely it is he/she will be held accountable, which can lead to further savings. Sub-meters tend to be less common in medium and small facilities, and more common in large energy-intensive facilities, but a large potential to use the data in energy management still exists in large industry.

4.4.2 Boiler, Steam, and Hot Water Systems[20]

Efficiency measure bundles applicable to boilers, steam systems and hot water systems include all the efficiency upgrade measures that improve the efficiency, or reduce the energy use, in these end uses. The energy reduction of a measure is compared to a standard efficiency water tube boiler (for medium and large boilers) or a standard efficiency fire tube boiler (for small boilers) without the measure. The following measures were identified and assessed:

- Economizer
- Blowdown heat recovery
- Boiler combustion air preheat
- Process heat recovery to preheat make-up water
- Condensing boiler
- First generation super boilers
- Direct contact hot water heaters
- Boiler right sizing and load management
- High-efficiency burner
- Insulation
- Advanced boiler controls including air/fuel mix control
- Blowdown control
- Boiler water treatment
- Boiler maintenance

[20] Unless otherwise noted, measure assumptions provided in this section are from Marbek's in-house database, which is compiled from a number of sources including previous and on-going studies, facility energy audits and surveys.

- Minimize deaerator vent losses
- Condensate return
- Steam trap survey and repair
- Instantaneous steam generation.

Economizer

Assumptions used for Analysis[21]	
Sub Sectors	Medium and large industry
Typical Measure Size/Specification	Application: 110 to 460 BHP boiler
Typical Measure Costs	$27,000 to $350,000
Typical Measure Savings	4%
Useful Measure Life	20 years

An economizer is a heat exchanger that is designed to use heat from hot boiler flue gases to preheat water. Economizers are often used on large utility steam boilers to preheat the feedwater using recovered stack heat. The same principle can be applied to smaller heating boilers where there is a nearby demand for hot water. These installations have become more economical as energy prices have risen and smaller, lighter and more durable economizers have been developed. A condensing economizer improves the effectiveness of reclaiming flue gas heat by cooling the flue gas below the dewpoint. The condensing economizer thus recovers both the sensible heat from the flue gas and the latent heat from the moisture that condenses. The condensate is highly corrosive and requires measures to ensure that it does not enter the boiler. New boilers generally include economizers, while a large percentage of existing boilers has the potential to be retrofitted with an economizer.

Blowdown Heat Recovery

Assumptions used for Analysis[22]	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Application: 50 to 460 BHP boiler
Typical Measure Costs	$23,000 to $200,000
Typical Measure Savings	2%
Useful Measure Life	20 years

The boiler blowdown process involves the periodic or continuous removal of water from a boiler to remove accumulated dissolved solids and/or sludge. During the process, water is discharged from the boiler to avoid the negative impacts of dissolved solids or impurities on boiler efficiency and maintenance. However, boiler blowdown wastes energy because the blowndown liquid is at about the same temperature as the steam produced. Much of this heat can be recovered by routing the blowndown liquid through a heat exchanger that preheats the boiler's make-up water. The recovered heat can be used

[21] Cameron Veitch of Combustion and Energy Systems Ltd. Telephone call to author, August 7, 2008.

[22] Natural Resources Canada. Office of Energy Efficiency. *Energy Efficient Boilers.* www.oee.nrcan.gc.ca/industrial/equipment/boilers.

to preheat boiler make-up water before it enters the deaerator, and for low-pressure steam to heat water inside the deaerator, which reduces the cost to run the deaerator and improves overall boiler efficiency. Blowdown heat recovery is more prevalent at larger boilers in large energy-intensive facilities, but it is believed that the market penetration of the measure is still relatively small, based on consultant experience.

Boiler Combustion Air Preheat

Assumptions used for Analysis[23,24]	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Application: 50 to 460 BHP boiler
Typical Measure Costs	$50,000 to $500,000
Typical Measure Savings	5%
Useful Measure Life	15 years

Combustion air preheaters are similar to economizers in that they transfer energy from the flue gases back into the system. In these devices, however, the energy is transferred to the incoming combustion air. The efficiency benefit is roughly 1% for every 40°F increase in the combustion air temperature. Changes in combustion air temperature directly affect the amount of combustion air supplied to the boiler and may increase or decrease the excess air. (See below under the advanced boiler control measure for a discussion on air-fuel ration control.) Preheating boiler combustion air has a relatively low market penetration rate on existing boilers.

Process Heat Recovery to Preheat Makeup Water

Assumptions used for Analysis	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Application: 50 to 460 BHP boiler
Typical Measure Costs	$70,000 to $400,000
Typical Measure Savings	6%
Useful Measure Life	20 years

Recovered process heat can be a good source of energy to preheat boiler make-up water. Waste heat can be captured from a clean waste stream that normally goes into the atmosphere or down the drain and used to heat the make-up water before it is sent to the boiler. Implementation of many potential opportunities is restricted due to factors such as the distance between the process and the boiler, the available heat in the in the process stream, the volume of the process stream and the consistency of the heat generation. Implementation of the measure is not widely practiced, especially in small- and medium-sized facilities. Consequently, a significant potential remains.

[23] U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. *Improving Steam System Performance: A Sourcebook for Industry*, 2004.

[24] Industrial Technologies Program. U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. *Energy Tips – Process Heating – Tip Sheet 1.*

Condensing Boiler

Assumptions used for Analysis[25]	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Application: 50 to 460 BHP boiler
Typical Measure Costs	$120,000 to $3,500,000
Typical Measure Savings	10%
Useful Measure Life	20 years

High-efficiency condensing boilers feature advanced heat exchanger designs and materials that extract more heat from the flue gases before they are exhausted. The temperature of the flue gases is reduced to the point where the water vapour produced during combustion condenses back into liquid form, releasing the latent heat, which improves energy efficiency.

Modern condensing boilers have energy efficiencies of 90% to 96%, compared with new conventional non-condensing models with energy efficiencies up to 85%. Many boilers over 20 years old typically operate at overall water-to-steam boiler efficiencies of less than 70%, making them good candidates for upgrading or replacement. A number of natural gas-fired condensing boilers are available, but very few oil-burning models are on the market. Installing new boilers generally occurs only at the end of the life of existing boilers or when expansion occurs.

First generation super boilers

First generation super boilers are an emerging technology. Based on consultation to define the Achievable Potential, it was concluded that the potential future market take up of the measure is too uncertain, and potentially limited, to be included in this study.

Direct Contact Hot Water Heaters

Assumptions used for Analysis	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Application: 24 to 430 BHP heater
Typical Measure Costs	$75,000 to $2,750,000
Typical Measure Savings	10%
Useful Measure Life	20 years

In direct contact hot water heaters the combustion gas is in direct contact with the water and there is no heat transfer medium between the gas and the water. An example is where incoming water flows downward through a vertical column filled with stainless steel packing rings. As cold water comes into direct contact with rising hot combustion air from a gas burner, a very rapid heat transfer occurs, absorbing the heat energy into the water. Compared to heat exchanger type water heaters, direct contact heaters are more efficient because they eliminate the performance reductions caused by heat losses via the

[25] Natural Resources Canada. Office of Energy Efficiency. *Energy Efficient Boilers: Boiler Savings.* www.oee.nrcan.gc.ca/industrial/equipment/boilers.

heat transfer medium and by fouling of the heat exchange surfaces and the associated energy losses. However, efficiency can be greatly reduced by high return fluid temperatures.[26] Direct contact hot water heaters are most often installed when an existing water heater needs to be replaced due to its age and associated increased maintenance requirements. The market penetration of the technology is relatively small and a significant potential exists to increase the market penetration.

Boiler Right Sizing and Load Management

Assumptions used for Analysis[27,28]	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Application: 50 to 460 BHP boiler
Typical Measure Costs	$70,000 to $2,700,000
Typical Measure Savings	10%
Useful Measure Life	20 years

An oversized boiler will turn on and off more often than a boiler that has been properly matched to the demand, which may result in boiler short-cycling losses. If the boiler is instead left on standby, short-cycling losses will be avoided but energy will be wasted in keeping the boiler on standby. Rather than sizing a boiler to meet the highest possible load, fuel savings can be achieved by adding a smaller boiler, sized to meet the plant's average loads, or by re-engineering the power plant to consist of multiple small boilers. Multiple small boilers offer reliability and flexibility to operators to follow load swings without over-firing and short cycling. Load management also helps to reduce load variation. As this measure is normally an end-of-life option there should be no incremental costs to right size a boiler, but a benefit exists by purchasing a smaller boiler. The market penetration of the measure is relatively small and depends on the replacement rate of existing boilers and installation of new boilers.

High-efficiency Burners

Assumptions used for Analysis	
Sub Sectors	Small, medium, and large industry
Typical Measure Size/Specification	Application: 50 to 460 BHP boiler
Typical Measure Costs	$48,000 to $400,000
Typical Measure Savings	5%
Useful Measure Life	20 years

Due to differing temperature requirements and wide range of boiler models, a wide variety of burners are available and burner technology is continuously improving. Improvement in boiler burner efficiency is mainly associated with optimum combustion efficiency and improving the heat profile inside the combustion chamber. The efficiency

[26] CADDET Energy Efficiency. *Ultra-high Efficiency Direct Contact Water Heater.* www.caddet.org.

[27] Industrial Technologies Program. U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. *Minimize Boiler Short Cycling Losses – Tipsheet*, 2006.

[28] U.S. Environmental Protection Agency. *Wise Rules for Industrial Efficiency: a Toolkit for Estimating Energy Savings and Greenhouse Gas Emissions*, 2003.

of boiler burners is closely linked with the boiler controls regulating the fuel-to-air ratio. For example, inefficient fuel-to-air ratio control will reduce the efficiency of the burner.

Insulation

Assumptions used for Analysis	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Steam pipe: 100 ft (25psi) to 1,000 ft (100psi)
Typical Measure Costs	\$20,000 to \$150,000[29]
Typical Measure Savings	5%
Useful Measure Life	15 years

Insulation increases the amount of energy available for end uses by decreasing the amount of heat lost from the distribution system. Insulation removed during maintenance is often not replaced, and older insulation deteriorates with time. To improve the energy efficiency of the system, regular insulation surveys assist in identifying areas with insufficient insulation. A significant amount of facilities do not have regular insulation surveys.

Advanced Boiler Controls

Assumptions used for Analysis	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Application: 50 to 460 BHP boiler
Typical Measure Costs	\$40,000 to \$200,000
Typical Measure Savings	3%
Useful Measure Life	15 years

An alternative to complex linkage designs, modern burners are increasingly using servomotors with parallel positioning to independently control the quantities of fuel and air delivered to the burner head. Controls without linkages allow for easy tune-ups and minor adjustments, while eliminating hysteresis, or lack of retraceability, and provide accurate point-to-point control. These controls provide consistent performance and repeatability as the burner adjusts to different firing rates. Variable frequency drives (VFDs) can also be used to more accurately control the air supply.

Other technologies included in combustion controls are metered control, cross limited control and oxygen and carbon monoxide trim controls. Advanced boiler controls are generally one of the first energy-efficiency measures a facility will implement to improve boiler energy efficiency. Although the measure has achieved a substantial market share, a large market still remains.

[29] U.S. Environmental Protection Agency. *Wise Rules for Industrial Efficiency: a Toolkit for Estimating Energy Savings and Greenhouse Gas Emissions.* 1998. (1998 cost escalated to 2008 cost).

Blowdown Control

Assumptions used for Analysis	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Application: 50 to 460 BHP boiler
Typical Measure Costs	$35,000 to $120,000
Typical Measure Savings	1%
Useful Measure Life	20 years

Boiler water must be blown down periodically to prevent scale from forming on boiler tubes. This process can be wasteful if too much is lost to blowdown. Automatic blowdown controls measure and respond to boiler water conductivity and acidity to ensure that only the right amount of blowdown water is used. Although automatic blowdown control is becoming a standard practice for new boilers, a large percentage of existing boilers do not have automated control.

Boiler Water Treatment

Assumptions used for Analysis[30]	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Application: 50 to 460 BHP boiler
Typical Measure Costs	$10,000 to $50,000
Typical Measure Savings	1%
Useful Measure Life	10 years

Properly conditioning boiler water can increase the efficiency of the boiler as well as extend the boiler's life. Some of the technologies that are employed to remove undesirable impurities from the water supply include reverse osmosis, electrodialysis and electrodialysis with current reversal. These are all known as membrane processes. Reverse osmosis uses semi-permeable membranes that let water through but block the passage of salts. In electrodialysis, the salts dissolved in the water are forced to move through cation-selective and anion-selective membranes, removing the ion concentration. Proper boiler water treatment is a relatively common practice, especially for larger boilers.

30 U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. *A Consumer's Guide to EE and RE: Industry Plant Managers & Engineers - Steam Boilers.* www.eere.energy.gov/consumer/industry/steam.html#opp2.

Boiler Maintenance

Assumptions used for Analysis	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Application: 50 to 460 BHP boiler
Typical Measure Costs	(equipment-specific O&M) $8,000 to $30,000
Typical Measure Savings	5%
Useful Measure Life	5 years

An upgraded boiler maintenance program, including optimizing the air-to-fuel ratio, burner maintenance and tube cleaning, can save about 2% of a facility's total energy use with an average simple payback of five months. Periodic measurement of flue gas oxygen, carbon monoxide, opacity and temperature provides the fundamental data required for a boiler tune-up.

A typical tune-up might include a reduction of excess air (and thereby excess oxygen, O2), boiler tube cleaning and recalibration of boiler controls. A comprehensive tune-up with precision testing equipment to detect and correct excess air losses, smoking, unburned fuel losses, sooting and high stack temperatures, can result in boiler fuel savings as high as 20%, while typical savings are in the order of about 8% boiler fuel usage.

Boiler maintenance programs are a relatively common practice, especially for large boilers and in energy-intensive industries.

Minimize Deaerator Vent Losses

Assumptions used for Analysis[31,32]	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Application: 50 to 460 BHP boiler
Typical Measure Costs	$35,000 to $150,000
Typical Measure Savings	2%
Useful Measure Life	20 years

A deaerator works to remove dissolved oxygen from boiler feedwater and must vent this oxygen, and any other non-condensable gases that were removed, into the atmosphere. A very small percentage of steam will also be venting when the gases are vented. The amount of steam vented should be minimized through proper operation and controls.

If the deaerator is operated at very high pressures, this may cause excessive venting of steam to the atmosphere. Instead, the deaerator tank should be operated to meet water chemistry requirements for oxygen and carbon dioxide rather than simply using pressure

[31] U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy Industrial Technologies Program. *Energy Tips – Steam – Tip sheet #18 deaerators.*

[32] U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. *A Consumer's Guide to EE and RE: Industry Plant Managers & Engineers - Steam Boilers*. www.eere.energy.gov/consumer/industry/steam.html#opp2.

and temperature as a guide. This measure has been implemented on a relatively limited scale.

Condensate Return

Assumptions used for Analysis[33]	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Application: 50 to 460 BHP boiler
Typical Measure Costs	$40,000 to $350,000
Typical Measure Savings	2%
Useful Measure Life	20 years

The primary purpose of an effective condensate recovery system is to make the most effective use of all remaining steam and condensate energy after process use. Condensate (water or condensed steam) reduces the quality of the steam but is too high in value to simply discard. Maximizing the amount of condensate that is returned to the boiler can save both energy and water treatment chemicals. The value of the condensate varies with its pressure and temperature, which depends on the operating pressure of the steam system. If boiler feedwater is 60°F, and the condensate is 212ºF, then each pound of condensate contains at least 162 BTUs; if the boiler is operating at 80% efficiency, then it represents 190 BTUs. Condensate under pressure and above 212ºF can be flashed to steam for additional energy value/recovery.

The feasibility of returning condensate to the boiler depends on the distance the condensate needs to be piped to the boiler, and the volume of the condensate. Longer distances and smaller volumes negatively affect the feasibility of returning the condensate. Condensate return has achieved a relatively significant market penetration, but a substantial number of boiler steam systems still do not include condensate return systems.

Steam Trap Survey and Repair

Assumptions used for Analysis[34]	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Application: 50 to 460 BHP boiler
Typical Measure Costs	$20,000 to $200,000
Typical Measure Savings	4%
Useful Measure Life	3 years

Steam traps are important to the performance of both end-use equipment and the distribution system. Traps provide for condensate removal with little or no steam loss. If the traps do not function properly, excess steam will flow through the end-use device or the condensate will back up into it. Excess steam loss will lead to costly operation while

[33] U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. *A Consumer's Guide to EE and RE: Industry Plant Managers & Engineers - Steam Boilers*. www.eere.energy.gov/consumer/industry/steam.html#opp2.

[34] U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. *A Consumer's Guide to EE and RE: Industry Plant Managers & Engineers - Steam Boilers*. www.eere.energy.gov/consumer/industry/steam.html#opp2.

condensate backup will promote poor performance and may lead to water hammer. Traps can also remove non-condensable gases that reduce heat exchanger effectiveness. Regular steam trap surveys are an important measure to identify faulty steam traps and steam leaks. Repairing the steam leaks and faulty steam traps will minimize steam losses and improve system efficiency.

Steam trap surveys and repair is generally one of the first energy-efficiency measures implemented by plants and the measure is implemented by a large segment of the Industrial sector.

Instantaneous Steam Generation

Assumptions used for Analysis[35,36]	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Application: 50 to 460 BHP boiler
Typical Measure Costs	$120,000 to $3,500,000
Typical Measure Savings	15%
Useful Measure Life	15 years

When a boiler is too big, boiler short-cycling losses may occur, as an oversized boiler will turn on and off more often than a boiler that has been properly matched to the demand. Every time the boiler turns on, extra energy is required to heat it back up to steady state. Conversely, a boiler left on standby will avoid the extra energy used to heat back up to steady state, but will waste energy while it is in standby. Instantaneous steam generators do not need to be left on standby and do not require a large amount of energy to reach steady state performance. The relatively small water content of a coil-type steam generator, for example, enables it to go from cold start-up to full steam output in approximately 5 minutes. Instantaneous steam generation systems can also be beneficial when full modulation, high-output turndown ratios or rapid start-ups are required. A large market potential exist for instantaneous steam generators.

[35] Clark, Larry S. *Coil-Type Steam Generator*s. 2001 Retrieved June 27, 2008 from www.vaporpower.com/media/FeaturebyLarryClark.pdf.

[36] Clark, Larry S. *Coil-Type Steam Generators for Heating Plant Applications*. 1999. Retrieved June 27, 2008 from www.vaporpower.com/media/HPAC_Art.pdf

4.4.3 Process Direct Heat (Furnaces / Kilns / Ovens / Dryers) [37]

Efficiency measure bundles applicable to process direct heat (furnaces/kilns/ovens/dryers) end use include all the efficiency upgrade measures that improve the efficiency or reduce the energy use applicable to the end use. The energy reduction of a measure is compared to the most common, standard efficiency technology available, without the measure. The following measures were identified and assessed:

- Exhaust gas heat recovery
- High-efficiency burner and burner controls (including oxy-gas direct impingement heating for steel annealing)
- Insulation
- Advanced heating and process control
- High-efficiency ovens
- High-efficiency dryers
- High-efficiency kilns
- High-efficiency furnaces
- Air curtains

Exhaust Gas Heat Recovery

Assumptions used for Analysis[38]	
Sub Sectors	All
Typical Measure Size/Specification	Applicable to: 2 to 100 MMBTU/h units (K/F/O/D)*
Typical Measure Costs	$30,000 to $900,000
Typical Measure Savings	15%
Useful Measure Life	15 years

* K/F/O/D: Kilns/Furnaces/Ovens/Dryers

Exhaust gas heat recovery increases efficiency because it extracts energy from the exhaust gases and recycles it back to the process. Significant efficiency improvements can be made on furnaces, kilns, dryers and ovens, even if they are already operating with properly tuned ratio and temperature controls.

For lower and medium temperature applications, heat recovery from flue gas can be used to preheat oven burners, or heat other media such as make-up air, feed product or ventilation make-up air. The energy saved in heat recovered from the flue gas is related to the temperature difference between the flue gas and the heated medium, and the savings depend upon finding applications where heat recovery is economic and improves the process. Heat or enthalpy wheels are used at a number of facilities to recover the heat. The actual energy savings and costs depend on the heat wheel implemented.

[37] Unless otherwise noted, measure assumptions provided in this section are from Marbek's in-house database, which is compiled from a number of sources including previous and on-going studies, facility energy audits and surveys.

[38] U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. *Improving Process Heating System Performance: A Sourcebook for Industry*. 2004.

New heat recovery technologies continue to be developed, such as heat wheels with a desiccant core to recover energy, which can operate with low-grade heat in more robust environments. Opportunities vary by sub sector. For example, in the Food sub sector, recovered flue gas can be used to provide heat at the dough-rising stage, or to provide hot water for other processes. Payback periods for heat recovery systems in medium- to low-temperature application, such as ovens and dryers, range between 2.5 and four years, and are dependent on the type of technology implemented and the application of the recovered heat.[39]

For high-temperature applications there are mainly four widely used methods: direct heat recovery to the product; using a recuperator to transfer heat from the outgoing exhaust gas to the incoming combustion air, while keeping the two streams from mixing; using a regenerator to store thermal energy for future use; and using a waste heat boiler.

Exhaust gas heat recovery is not very common in process direct heat applications and, therefore, a large market potential for the measure exists.

High-efficiency Burners

Assumptions used for Analysis[40]	
Sub Sectors	All
Typical Measure Size/Specification	Applicable to: 2 to 100 MMBTU/h units (K/F/O/D)*
Typical Measure Costs	$15,000 to $500,000
Typical Measure Savings	10%
Useful Measure Life	20 years

* K/F/O/D: Kilns/Furnaces/Ovens/Dryers

Due to differing temperature requirements and applications, a wide variety of burners are available. Burner technology is also continuously improving. Efficient burner technology generally recovers heat from the flue gas and includes recuperative and regenerative style burners. These burners are more efficient at higher-temperature applications. Advancements over the past five years include the commercialization of self-recuperative and self-regenerative burners that use staged combustion to achieve flameless combustion. This results in more uniform heating, lower peak flame temperatures, improved efficiency and lower NO_x emissions.

There are numerous other types of high-temperature burner technologies that improve on previous technologies. Examples include rotary burners, dilute oxygen combustion (DOC) systems, oscillating combustion and low-NO_x burners with a vacuum-swing-adsorption (VSA) oxygen system, referred to as air-oxygen/fuel burner. More specifically:

- Rotary burners control gas pressure to ensure the desired fuel-to-air ratio.

[39] Ernest, Orlando. Lawrence Berkley National Laboratory. *Energy Efficiency Improvement and Cost Saving Opportunities for the Vehicle Assembly Industry*. 2003. Report reference number: LBNL 50939.

[40] U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. *Improving Process Heating System Performance: A Sourcebook for Industry*. 2004.

- Dilute oxygen combustion relies on the rapid and complete mixing of fuel and oxygen jets with hot furnaces gases containing low levels of oxygen.
- Oscillating combustion systems use a valve to oscillate the fuel flow rate to the burner. Oscillation creates successive fuel-rich and fuel-lean zones within the flame. Heat transfer to the load is increased due to more luminous fuel rich-zones and the break up of the thermal boundary layer, which shortens heat-up times.
- Air-oxygen/fuel burners use an innovative air-oxy-natural gas burner that achieves high productivity and energy efficiency with low NO_X emissions.

Modern burners are increasingly using servomotors with parallel positioning to independently control the quantities of fuel and air delivered to the burner head. These controls provide consistent performance and repeatability as the burner adjusts to different firing rates. Alternatives to electronic controls are burners with a single drive or jackshaft.[41]

Examples of advanced burner technologies include radiation stabilized burners (RSB), forced internal recirculation (FIR) burners and the low-swirl burners (LSB). More specifically:

- The RSB is a fully pre-mixed, semi-radiant, surface stabilized burner, developed to provide high thermal efficiency and very low emission of NO_x and CO in industrial boilers and process heaters.

- The FIR burner aims to reduce emissions while maintaining the boiler efficiency. The FIR burner operates with pre-mixed sub-stoichiometric combustion and significant internal recirculation of partial combustion products. Both the RSB and FIR burners are available commercially.

- The LSB is being developed to achieve ultra-low NO_x emissions and increase system efficiency. The burner system combines a low-swirl flame stabilization method with internal flue gas recirculation. It is also being optimized to utilize partially reformed natural gas.

In addition to the high-efficiency burners discussed above, the use of oxy-gas is one of the major efficiency improvements applicable to high-temperature applications, such as furnaces and kilns. Replacing air with oxygen eliminates the need to heat and process large volumes of nitrogen present in air. This reduces energy use and enables a reduction in equipment size. In many industrial activities, air quality regulations drive the demand for high efficiency but low emissions (NO_x, CO) in the combustion process. NO_x formation is reduced by reducing the amount of nitrogen in contact with oxygen at high flame temperatures.

Oxy-fuel burners are used throughout industry, including the steel and glass sectors. The high velocities of the gases in the burner ensure that the fuel is completely combusted at a lower temperature zone of the flame. An earlier case study in the metal casting industry

[41] U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. Industrial Technologies Program. *Energy Tips – Steam – Upgrading Boilers to High-efficiency Burners.*

reviewed the installation of an oxy-fuel melting furnace in an iron foundry. The furnace achieved a reduction in energy use, an improvement in operational costs and had a lower initial investment cost than a conventional electric furnace.[42]

The use of oxy-gas direct flame impingement (DFI) is specifically applicable to stainless steel annealing. DFI is based on a large number of small oxy-fuel burners that are positioned in rows close to the steel strip in order to realize oxy-fuel flames that are directly impinging the strips. Production capacity increases after the installation of the DFI oxy-gas unit and improves the energy efficiency.[43]

Insulation

Assumptions used for Analysis[44]	
Sub Sectors	All
Typical Measure Size/Specification	Applicable to: 2 to 100 MMBTU/h units (K/F/O/D)*
Typical Measure Costs	$8,000 to $250,000
Typical Measure Savings	5%
Useful Measure Life	15 years

* K/F/O/D: Kilns/Furnaces/Ovens/Dryers

Heat loss can cause significant reduction in process heating efficiency. Insulation of equipment and pipes increases the amount of energy available for end uses by decreasing the amount of heat lost from the system. New refractory fiber material with low thermal conductivity and heat storage can produce significant improvements in efficiency. Typical applications include furnace covers, installing fiber liner between the standard refractory lining and the shell wall or installing ceramic fiber liner over the present refractory liner. Replacing standard refractory linings with vacuum-formed refractory fiber insulation can also improve efficiency. It is reported that installing a furnace with refractory fiber liners can improve thermal efficiency of the heating process by up to 50%.[45]

Insulation removed during maintenance is often not replaced, and older insulation deteriorates with time. To improve the energy efficiency of the system, regular insulation surveys assist in identifying areas with insufficient insulation. A significant amount of facilities do not have regular insulation surveys.

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42 Ernest, Orlando. Lawrence Berkley National Laboratory and the American Council for an Energy Efficient Economy (ACEEE). Emerging Energy-Efficient Industrial Technologies. 2000. Report reference number: LBNL 46990.

43 Gas, L. *State-of-the-art Oxyfuel Solutions for Reheating and Annealing Furnaces in Steel Industry*. 2007. Presentation retrieved www.linde-gas.com/rebox.

44 U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy; *Improving Process Heating System Performance: A Sourcebook for Industry,* 2004.

45 U.S. Environmental Protection Agency; *Wise Rules for Industrial Efficiency: a Toolkit for Estimating Energy Savings and Greenhouse Gas Emissions*, 1998.

Advanced Heating and Process Control

Assumptions used for Analysis[46]	
Sub Sectors	Medium and large industry
Typical Measure Size/Specification	Applicable to: 2 to 100 MMBTU/h units (K/F/O/D)*
Typical Measure Costs	$100,000 to $500,000
Typical Measure Savings	10%
Useful Measure Life	15 years

* K/F/O/D: Kilns/Furnaces/Ovens/Dryers

Advanced heating and process controls refer to opportunities to reduce energy losses by improving control systems that govern aspects such as material handling, heat storage and turndown. These also include process thermal optimization measures. Energy losses that are generally attributable to system operation during periods of low throughput are addressed. Some advanced controls use a programmed heating temperature setting for part load operation; they also monitor and control exhaust gas oxygen as well as unburned hydrocarbon and carbon monoxide emissions. Advanced heating and process controls are often one of the first energy-efficiency measures a facility will implement to improve energy efficiency. Although the measure has achieved a substantial market penetration, a large market still remains.

High-efficiency Ovens

Assumptions used for Analysis	
Sub Sectors	Paper, Chemical, Transportation and Machinery, Non-metallic Mineral, Miscellaneous, Food and Beverage
Typical Measure Size/Specification	Applicable to: 2 to 100 MMBTU/h ovens
Typical Measure Costs	Incremental cost: $18,000 to $1,000,000
Typical Measure Savings	12%
Useful Measure Life	20 years

Specific to: Paper, Chemical, Transportation and Machinery, Non-metallic Mineral, Miscellaneous

Infrared (IR) ovens use less energy than convection ovens because they heat the parts directly. Unlike convection ovens, they do not heat the air. IR ovens may also be used as a booster oven where final curing requires convection heating. Production rates may increase significantly when an IR oven replaces a convection oven. IR ovens can either replace existing convection ovens or be an addition to an existing one.

Natural gas savings were reported where an IR oven was used as a booster oven. Production speed increases of up to 50% were also reported. A simple payback period of 2.5 years is reported for the installation of an IR oven as a booster oven.[47] In cases where

[46] U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. *Improving Process Heating System Performance: A Sourcebook for Industry*. 2004.

[47] U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy, Industrial Technology Program. *Infrared oven saves energy, lifts production at a metal finishing plant.* 2004.

IR ovens replaced convection ovens, reported simple payback periods ranged between 10 months and 3.5 years.[48]

Airflow in convection ovens is important to ensure uniform distribution of heated air, which improves product quality and optimizes the volume of heated air required. In medium- to low-temperature applications, some energy-efficient units incorporate internal recycling of airflow to optimize airflow distribution. Air heat seals at the entrance and exit of units limit heat loss with airflow. (See also Air Curtains measure.)

Heat recovery from flue gas can be used to preheat oven burners, or heat other media like make-up air or product. (See also the Flue Gas Heat Recovery measure.)

Specific to: Transportation and Machinery

Research relevant to paint ovens includes developing paints or coatings that cure faster, or requires less energy to cure. Powder slurry coats are an example of a newer type of paint that requires less energy. The application of powder slurry coats does not require the base coat to be heated to high temperatures, with the result that energy is saved in the drying process. A wet-on-wet painting process eliminates the baking process between the two coats of paint; Honda and Toyota have used this process at their facilities since 1998.

Specific to: Food and Beverage Sub Sector

A wide range of oven sizes and designs are used in the Food and Beverage sub sector. Advances in oven energy efficiency are primarily related to improved control systems, improved combustion efficiency, reduced energy losses and reclaiming heat from exhaust gas. (See also the Exhaust Gas Heat Recovery and High-efficiency Burners measures.) Actual energy use and efficiencies also vary widely depending on oven type and application.[49]

Reducing the speed of the recirculation fan and reducing the exhaust rate can minimize the energy loss when the oven is in standby mode, which maintains the temperature of the oven, for example, when the door is open.

The reported average payback period for eight heat recovery projects at various international locations is four years.[50] The inclusion of improved burners, control systems and insulation would further decrease the payback period.

As an end-of-life measure, the implementation of high-efficiency ovens is dependent on the turnover rate of existing ovens and the need for new ovens.

[48] Ernest, Orlando. Lawrence Berkley National Laboratory. *Energy Efficiency Improvement and Cost Saving Opportunities for the Vehicle Assembly Industry*. 2003. Report reference number: LBNL 50939.

[49] U.S. Gas Research Institute – Energy Utilization Centre: Research Collaboration Program. *Food Processing Technology Project – Phase 1*. 2003.

[50] Ernest, Orlando. Lawrence Berkley National Laboratory and the American Council for an Energy Efficient Economy (ACEEE). Emerging Energy-Efficient Industrial Technologies. 2000. Report reference number: LBNL 46990.

High-efficiency Dryers

Assumptions used for Analysis	
Sub Sectors	Food and Beverage, Chemical, Paper, Miscellaneous
Typical Measure Size/Specification	Applicable to: 2 to 100 MMBTU/h ovens
Typical Measure Costs	$18,000 to $1,000,000
Typical Measure Savings	12%
Useful Measure Life	20 years

A large variety of dryers, ranging in size and design, are used in the Food, Chemical, Paper and Miscellaneous sectors. Besides the design of dryers, advances in energy efficiency include improving control systems, improving combustion efficiency, reducing energy losses and reclaiming heat from exhaust gas. (See also the Gas Exhaust Heat Recovery, High-efficiency Burners and Advanced Heating and Process Control measures.)

Advanced drying technology usually aims to improve the heat transfer between the combustion gas and the product, for example the pulsed fluidized bed dryer, helix dryer and the pulse combustion flash dryer. The pulsed fluidized bed dryer uses a periodic hot air supply and has a wide range of applications. The helix dryer is a cylindrical chamber with a centrally located hollow column through which hot gas is supplied to the helical trays. The pulse combustion flash dryer uses intermittent combustion of fuel, which generates intensive pressure, velocity and temperature waves. The helix dryer must still be proven on a commercial scale, while the other two technologies are available for commercial applications. Energy use and efficiencies also vary widely depending on dryer type and application.[51]

Replacing a steam system with direct-fired systems can save a significant amount of natural gas. One example is the implementation of a direct-fired gas system to dry barley in a malting plant; pre-drying stages or multiple drying stages can increase the production rate and reduce the natural gas consumption per production unit.

The implementation of high-efficiency dryers is dependent on the turnover rate of existing dryers and the need for new dryers.

[51] U.S. Gas Research Institute – Energy Utilization Centre: Research Collaboration Program. *Food Processing Technology Project – Phase 1*. 2003.

High-efficiency Kilns

Assumptions used for Analysis	
Sub Sectors	Non-metallic Mineral
Typical Measure Size/Specification	Applicable to: 20 to 100 MMBTU/h furnaces
Typical Measure Costs	\$100,000 to \$1,000,000
Typical Measure Savings	14%
Useful Measure Life	20 years

Roller kilns, using rapid firing technology, are more efficient than conventional tunnel kilns in the clay and ceramic industries. In the rapid firing process, the clay is prepared dry and the reduced water content results in reduced heating times. Roller kilns are successfully used in Europe and the U.S. Current kilns may have single or double layer designs and are well suited for ceramic products, but may be less suited for larger capacity brick kilns. Energy performance can be improved by heat recovery from the flue gases and retrofitting or installing improved insulation with low thermal mass materials (LTM). A simple payback period of 3.2 years is reported for the installation of a roller kiln in the place of a tunnel kiln, and relatively high fuel savings are reported when tunnel kilns are replaced with roller kilns and improved LTM insulation.[52]

Suppliers of roller kilns are developing multi-layer kilns, which will increase production rates and reduce the rate of energy usage per production unit. Additional fuel savings will be associated with improved heat recovery, burner design and control systems. (See also the Gas Exhaust Heat Recovery, High-efficiency Burners and Advanced Heating and Process Control measures.)

Similar to high-efficiency ovens and dryers, the implementation of high-efficiency kilns is dependent on the turnover rate of existing kilns and the need for new kilns. The lifespan of kilns are relatively longer than ovens and dryers, and a large percentage of older kilns (compared to ovens and dryers) are present in some sectors.

High-efficiency Furnaces

Assumptions used for Analysis	
Sub Sectors	Primary Metal, Transportation and Machinery and Non-metallic Mineral (medium and large facilities)
Typical Measure Size/Specification	Applicable to: 20 to 100 MMBTU/h furnaces
Typical Measure Costs	Incremental cost: \$100,000 to \$1,000,000
Typical Measure Savings	14%
Useful Measure Life	20 years

The main advances in furnaces are related to combustion control, waste-heat recovery and better design. Preheating combustion air using high-velocity burners, pulse firing, recuperators or regenerative burners can improve the heat transfer of the combustion

[52] Ernest, Orlando. Lawrence Berkley National Laboratory and the American Council for an Energy Efficient Economy (ACEEE). Emerging Energy-Efficient Industrial Technologies.2000. Report reference number: LBNL 46990.

system. Specific improvements are usually applicable to specific furnaces. (See also the High-efficiency Burners measure profile.)

Advanced furnace design includes highly preheated combustion air system with/without oxygen enrichment.[53] Porous wall radiation barrier (PWRB) heating mantles reportedly results in a heat-transfer rate in the 1,800°F to 2,400°F range that is two to four times greater than conventional gas-fired mantles.[54] Improvement in insulation material will reduce heat losses from the furnace shell. Research to develop new composite materials for insulation is undertaken at the Lawrence Berkley National Laboratory and is expected to contribute to the overall efficiency of furnaces.[55]

Specific to: Primary Metal and Transportation and Machinery Sectors

Recycled aluminum production uses 90% less energy than primary aluminum production. Several new technologies have emerged that help to improve the recovery or processing of scrap, or reduce energy use in the preparing and melting of scrap. Examples include a decoating kiln (the IDEX™), which reported a relatively high reduction in kiln energy use, and a new melt design that preheats and decoats the scrap in a dry hearth furnace and then melts the scrap in a closed well furnace.

Specific to: Non-Metallic Mineral Sector

State-of-the-art furnace technology in glass production uses a higher percentage of recycled glass, also called cullet. Glass manufactured in North America contains on average 20% cullet, while European container glass manufacturers sometimes use 80% cullet. Increasing cullet use by 10% reduces fuel use by approximately 2.5%.

Increasing the cullet percentage in glass containers requires more effective and efficient waste glass collection. The reported simple payback period for furnaces with 100% cullet percentage and cullet preheating is two years. Energy efficiency can be further improved by batch cullet preheating and by recovering the flue gas heat. Cullet preheaters have been under development since 1980 and commercial applications can be found in Europe, while development projects are ongoing in the U.S.

Similar to high-efficiency ovens, dryers and kilns, the implementation of high-efficiency furnaces is dependent on the turnover rate of existing furnaces and the need for new furnaces. The lifespan of furnaces is relatively longer than ovens and dryers, and a large percentage of older furnaces (compared to ovens and dryers) are present in some sectors.

[53] U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. Industrial Technologies Program. *Development of a highly preheated combustion air system with/without oxygen enrichment*. 2004.

[54] U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. *Combustion Fact Sheet: Innovative energy-efficient high-temperature gas-fired furnace*. 2001.

[55] U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. *Industrial Material for the Future Project Fact Sheet: Advanced nanoporous composite materials for industrial heating application*s. 2002.

Air Curtains

Assumptions used for Analysis[56,57]	
Sub Sectors	Small and medium industrial facilities
Typical Measure Size/Specification	Applicable to: 2 to 20 MMBTU/h units (O/D)*
Typical Measure Costs	$15,000 to $100,000
Typical Measure Savings	15%
Useful Measure Life	20 years

* O/D: Ovens/Dryers

Air heat seals at continuous oven and dryer entrances and exits limit heat loss with airflow. Air curtains are generally not applicable to batch operations. Air curtains are not usually technically feasible at high-temperature processes, such as kilns and furnaces, due to the process lay out, the high-temperature differential and if the processes operate as batch processes.

In a typical application, a heat seal draws hot interior air and compresses it in scroll fans. Centrifugal fans are used to create an air curtain at oven and dryer openings. When used on oven/dryer openings, air curtains are normally installed horizontally over the opening and angled slightly inward to contain the hot air. Air heat seals can be installed as a retrofit or a new installation.

Air curtains are not very common in industrial plants.

4.4.4 Other Process

Other process efficiency measures include all the upgrade measures that improve efficiency or reduce the energy use applicable to specific processes in sub sectors. The energy reduction of a measure is compared to the most common, standard efficiency technology available, without the measure. The following measures were identified and assessed:

- Pollution control measures
- Computational fluid dynamic modeling
- Hydrogen atmospheres for steel batch coil annealing
- Process heat recovery
- Process integration and pinch analysis.

Specific information about the measure was retrieved from in-house Marbek data, unless otherwise specified.

[56] Hank Specialty Equipment. *Air Curtains*. www.hankinspecialty.com/aircurtain.html.

[57] Miniveil Air Systems. *Air Curtain Usage*. www.miniveil.com/uses.html.

Pollution Control Measures

Assumptions used for Analysis	
Sub Sectors	Medium and large industry
Typical Measure Size/Specification	Applicable to: 5,000 to 500,000 scfm
Typical Measure Costs	Incremental cost: $80,000 to $1,000,000[58]
Typical Measure Savings	10%
Useful Measure Life	20 years

Regenerative thermal oxidizers (RTOs) are generally used as a pollution control mechanism to destroy volatile organic compounds (VOCs) and are assumed to be the baseline technology. RTOs use high temperatures to incinerate and destroy VOCs. Regenerative catalytic oxidizers (RCOs) use a catalyst to enable the RCO to operate at a lower temperature than the RTO. RCOs provide the same level of VOC destruction efficiency as RTOs, but offer lower natural gas consumption. Large energy-intensive industries in sub sectors that are subject to emission regulations are more inclined to have energy-efficient pollution control measures but the market penetration of the measure is still relatively limited.

Computational Fluid Dynamic (CFD) modeling

CFD modeling is used as a tool to identify energy savings opportunities and does not generate savings *per se*. The opportunities identified are captured by the other measures and, if CFD modeling were included, it would result in a double counting of the savings. CFD modeling was therefore excluded from the study.

Hydrogen Atmospheres for Steel Batch Coil Annealing

Assumptions used for Analysis[59,60]	
Sub Sectors	Miscellaneous
Typical Measure Size/Specification	Applicable to: 20 to 100 MMBTU/h process units
Typical Measure Costs	$250,000 to $2,000,000
Typical Measure Savings	30%
Useful Measure Life	15 years

The modernization of existing HN batch anneal facilities to H_2 operation can range from simply retrofitting equipment to the safe use of pure H_2 as the process atmosphere, to a full conversion to state-of-the-art high-performance hydrogen technology. Increasing throughput is generally the primary reason to upgrade, but cost savings also result from reduced consumables and labour, increased product quality and yield and the capability to produce higher profit margin grades.

[58] U.S. Department of Energy. Office of Energy Efficiency and Renewable Energy. *Air Pollution Control Technology Fact Sheet.* EPA-425/F-03-021.

[59] Brooks, R. *California Style: All New, All Hydrogen*. 2001. RAD-CON, Inc. www.rad-con.com/pdf/California%20Style.pdf.

[60] Gasse, W. *Benefits of converting HN batch annealing to hydrogen*. 2002. Retrieved June 27, 2008 from www.allbusiness.com/primary-metal-manufacturing/iron-steel-mills-ferroalloy/344606-1.html.

Hydrogen has a thermal conductivity approximately seven times greater and a density of one-fourteenth that of nitrogen. Upgrading the batch anneal equipment to H_2 capability provides an overall improvement in heat transfer of the process atmosphere itself and allows the further increase in convective heat transfer through increasing process atmosphere recirculation flow rates.

As a result, the required thermal uniformity within the coil (Delta temperature, or the difference between the hot exterior and the coldest position in the core of the coil) is achieved within a shorter period of time, meaning equivalent micro-structural and mechanical properties uniformity is achieved with higher throughput and reduced utilities consumption. As H_2 is much more efficient in transferring heat into the body of the coil, overheating of coil exterior surfaces is greatly reduced or eliminated entirely, resulting in increased yield of prime material. Superior mechanical properties are also made possible by the ability to realize reduced Delta temperature than can be achieved with old HN equipment. Modernization can increase heating throughput by 50% to 200% relative to the old HN operation, depending upon the recirculated process atmosphere flow generated by the base motor and impeller and the fuel gas consumption rating of the furnace.

Based on information from Ontario suppliers, the implementation of hydrogen atmospheres is relatively mature and close to half of the potential market has been captured.

Process Heat Recovery

Assumptions used for Analysis	
Sub Sectors	All
Typical Measure Size/Specification	Applicable to: 2 to 100 MMBTU/h process units
Typical Measure Costs	$30,000 to $1,000,000
Typical Measure Savings	15%
Useful Measure Life	15 years

Process heat recovery includes the use of waste heat from industrial processes to heat other processes or utility streams. A wide range of heat recovery opportunities exists, including heat transfer between a heat source and a heat sink, where the heat sink and heat source could be either gas, liquid or solid. The feasibility of process heat recovery opportunities depend in large part on the quality of the heat, the distance between the heat source and heat sink, potential cross contamination of product, properties of the process stream (such as corrosiveness), the flow rates of the streams and the fluctuation in the flow rates. Although the concept of process heat recovery is very mature, its participation rate in industry is still relatively low.

Process Integration and Pinch Analysis

Process integration and pinch analysis are used as tools to identify energy savings opportunities and do not generate savings *per se*. The opportunities identified are captured by the other measures and, if process integration and pinch analysis were included, it would result in a double counting of the savings. This measure was therefore excluded from the study.

4.4.5 HVAC[61]

Efficiency measure bundles applicable to the heating, ventilation and air conditioning (HVAC) end use include all the upgrade measures that improve the efficiency, or reduce the energy use applicable to the end use. The energy reduction of a measure is compared to the most common, standard efficiency technologies, without the applicable measure. The following measures were identified and assessed:

- Radiant heaters
- Automated temperature control
- Solar walls
- Ventilation heat recovery and optimization
- Warehouse loading dock seals
- Air curtains
- Air compressor heat recovery
- Destratification fans.

Radiant Heaters

Assumptions used for Analysis	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Applied to small, medium and large facilities
Typical Measure Costs	$30,000 to $200,000
Typical Measure Savings	25%
Useful Measure Life	20 years

Radiant heating equipment is designed to provide comfort heating through the application of radiant heat transfer. Radiant heaters work by emitting heated infrared rays, which are absorbed by objects, such as floors, equipment or people. Infrared heat rays do not warm the air, although the air immediately surrounding the "heated" objects is warmed by the increase in temperature of those objects. These systems are very efficient compared to convection type heaters and can use significantly less natural gas than a natural gas-fired convection heating system. Radiant heating technology is mature and data indicated that close to one-third of the potential market is already captured.[62]

[61] Unless otherwise noted, measure assumptions provided in this section are from Marbek's in-house database, which is compiled from a number of sources including previous and on-going studies, facility energy audits and surveys.

[62] Zulfiqar A. *An Insight Into The Union Gas Industrial Segment*. Union Gas Report, 2007.

Automated Temperature Control

Assumptions used for Analysis	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	N/A
Typical Measure Costs	$12,000 to $70,000
Typical Measure Savings	15%
Useful Measure Life	20 years

Automatic temperature controls allow the temperature in different areas to be varied according to a schedule, in order to save energy during times when a space need not be heated or cooled as much. These controls may also prevent individuals from manually changing the temperature settings. Automated temperature controls for comfort heating are relatively common in industrial plants and have reportedly achieved close to 50% market penetration.[63]

Solar Walls

Assumptions used for Analysis[64]	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	500 watts/square meter[65]
Typical Measure Costs	$100,000 - $250,000
Typical Measure Savings	15%[66]
Useful Measure Life	20[67]

Solar walls use solar energy to preheat outside air before it is introduced into a plant. The warmed air can be distributed as is, further heated in a building's primary heating system or used as combustion air for industrial furnaces. Because the air going into the system is already warm, less energy is needed to heat it further.

Solar walls are typically made of dark metal cladding, usually unglazed corrugated aluminum, which is mounted over a south-facing wall. Sunlight hitting the cladding warms the air near its surface, which is then drawn through thousands of small perforations in the cladding into a narrow space between the wall and the building. The heated air rises to an overhanging canopy plenum where it is drawn into the facility by fans and dampers. A solar wall is virtually maintenance free, with no liquids or moving parts other than the ventilation system fans. Solar walls have achieved little market penetration in Ontario industrial facilities.

[63] Zulfiqar A. *Industrial Usage and Energy Efficiency Study: Top Line Results*. Union Gas Report, 2006.

[64] Natural Resources Canada. *Solar Air Heating*. 2007. www.canren.gc.ca/prod_serv/index.asp?CaId=137&PgId=742.

[65] Conserval Engineering. *Solar Air Heating and Ventilation with SolarWall Systems*. Retrieved May 20, 2008 from http://solarwall.com/en/products/solarwall-air-heating.php.

[66] Ibid.

[67] Ibid.

Ventilation Heat Recovery and Optimization

Assumptions used for Analysis	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	12,000 cfm
Typical Measure Costs	$25,000 to $150,000
Typical Measure Savings	17%
Useful Measure Life	20 years

Two types of heat recovery and optimization technologies are included in the measure: BKM reverse flow heat recovery system and heat wheels.

A BKM reverse flow heat recovery system is an air-to-air heat exchanger that collects the thermal energy in air that is exhausted from a facility and uses it to preheat fresh make-up air that is brought in to replace the exhausted air. These units use two heat sinks, which are alternately used to either heat the incoming air, or cool the exhaust air, and switch roles every 70 seconds.

An enthalpy wheel, or heat wheel, is a type of energy recovery ventilator that uses a rotating energy exchanger in the form of a cylinder. The cylinder is packed with a heat transfer medium with many small air passages, or flutes, that run parallel to the direction of airflow. In a typical installation, the wheel is positioned in a duct system such that it is divided into two half moon sections. Stale air from the conditioned space is exhausted through one half, while outdoor air is drawn through the other half in a counter flow pattern. At the same time, the wheel is rotated slowly. Sensible heat is transferred as the metallic substrate picks up and stores heat from the hot air stream and gives it up to the cold one. Latent heat is transferred as the medium condenses moisture from the air stream that has the higher humidity ratio.

This energy-efficiency measure has achieved a relatively small market penetration and a significant potential for a higher participation rate exists.

Warehouse Loading Dock Seals

Assumptions used for Analysis[68]	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	N/A
Typical Measure Costs	$10,000 to $40,000
Typical Measure Savings	5%
Useful Measure Life	10 years

Warehouse loading dock seals provide a barrier between the back of a docked truck and the edges of the loading dock opening. An improper seal may result in drafts and a loss of heat from the warehouse. Although this measure is easy to implement, it is a relatively neglected efficiency area with a large potential for market penetration.

[68] Bondor Manufacturing Company. *Foam Truck Dock Seals*.
www.bondorseals.com/more_info/dock_seals_all_types/foam_truck_dock_seals/foam_truck_dock_seals.htm.

Air Curtains

Assumptions used for Analysis	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	2 to 8 Standard loading dock doors
Typical Measure Costs	$13,000 to $40,000
Typical Measure Savings	5%
Useful Measure Life	15 years

Open loading dock doors may lose a large amount of heat between the time they are opened and when a truck is docked. An air curtain at the loading dock door acts as a thermal barrier, lowering the amount of energy lost through the opening. Air curtains work by generating a jet of high-velocity air that separates the two sides of the jet, forming a screen or curtain. The air curtain should be activated as soon as the loading dock door is opened and then stopped once it is closed in order to conserve energy. Air curtains can either be heated or unheated, depending on the application requirement. Although air curtain technology is a very mature technology, its reported market penetration is very small.[69]

Air Compressor Heat Recovery

Assumptions used for Analysis	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	N/A
Typical Measure Costs	$18,000 to $100,000
Typical Measure Savings	15% of heating costs
Useful Measure Life	20 years

Typically, the warm exhaust gas produced by plant air compressors is discharged outside the building. Using this exhaust during winter to replace outside make-up air can significantly reduce the cold make-up air supply. Installing a duct that joins the compressor gas exhaust to the existing plant air distribution system ensures that the warm air is distributed evenly through the plant. During summer months the exhaust gas from the compressors will still need to be vented to outside the building. Although this measure is very mature, its reported market penetration is very small.[70]

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[69] Zulfiqar A. *Industrial Usage and Energy Efficiency Study: Top Line Results*. Union Gas Report, 2006.

[70] Zulfiqar A. *An Insight Into The Union Gas Industrial Segment*. Union Gas Report, 2007.

Destratification Fans

Assumptions used for Analysis[71,72]	
Sub Sectors	Small, medium and large industry
Typical Measure Size/Specification	Applied to small, medium and large plants
Typical Measure Costs	$10,000 to $60,000
Typical Measure Savings	8%
Useful Measure Life	20 years

The air temperature in large, high ceiling storage rooms can become stratified (i.e., air is layered at different temperatures at different levels). Destratification fans are high-volume, low-speed fans that mix the air and eliminate stratified layers of temperature in large spaces. These types of fans use a comparable amount of energy as conventional, small ceiling fans, but since fewer fans are required, the total energy required is reduced. High-volume, low-speed destratification fans have been on the market for a number of years and are at the early stages of market penetration.

4.5 TECHNOLOGY DATA AND INFORMATION AS INPUT FOR ECONOMIC AND ACHIEVABLE POTENTIAL FORECASTS

The technology data and information presented in this section was used as input data in the measure TRC assessment, described above in Sections 4.2 and 4.3. The detailed results of the TRC input assumptions and results are provided in Appendix D. The measures that have a positive TRC are included in the Economic Potential and Achievable Potential assessment, which are discussed in Sections 5 and 6. As discussed under Section 4.3 all the measures had a positive TRC in at least one sub sector for the large technology size. It should be noted that the following measures listed in Exhibits 1.1 and 4.4 were not assessed: first generation super boilers, computational fluid dynamic modelling, and process integration and pinch analysis. The reasons for the exclusion of these measures are described in the respective descriptions in Section 4.4.

71 Big Ass Fans. www.bigassfans.com/howitworks.php.

72 Envira-North Systems. *Destratification Fans*. www.enviranorth.com.

5. ECONOMIC POTENTIAL FORECAST

5.1 INTRODUCTION

This section presents the Industrial sector Economic Potential Forecast for the study period (2007 to 2017). The Economic Potential Forecast estimates the level of natural gas consumption that would occur if all process equipment and building envelopes were upgraded to the level that is cost effective. In this study, "cost effective" means that the technology upgrade passes the measure total resource cost (TRC) test, as discussed previously in Section 4.2.

The discussion in this section is organized into the following subsections:

- Major modeling tasks
- Technologies included in Economic Potential Forecast
- Presentation of results
- Interpretation of results.

5.2 MAJOR MODELING TASKS

By comparing the results of the Industrial sector Economic Potential Forecast with the Reference Case, it is possible to determine the aggregate level of potential natural gas savings within the Industrial sector, as well as identify which specific sub sectors, end uses and technologies provide the most significant opportunities for savings.

To develop the Industrial sector Economic Potential Forecast, the following tasks were completed:

- The measure TRC results for each of the energy-efficiency upgrades and equipment sizes (small, medium, large) presented in Exhibit 4.3 were reviewed.

- Technology upgrades that had positive measure TRC results were selected for inclusion either on a "full cost" basis for retrofit measures, or an "incremental" basis for end-of-life measures. Technical upgrades passing the measure TRC test on a "full cost" basis were implemented in the first forecast year. Those upgrades that passed the measure TRC test on an "incremental" basis were introduced as the existing stock reached the end of its useful life.

- Energy use within each of the sub sectors was modelled with the same energy models used to generate the Reference Case. However, for this forecast, the remaining standard efficiency technologies included in the Reference Case were replaced with the most efficient "technology upgrade option" that passed the measure TRC test.

- When multiple measures passed the economic screen and were applicable to a given end use, the first measure selected was the one that provided the largest energy savings. This typically meant that equipment replacement (e.g., a high-efficiency boiler) was applied first in the model, followed by retrofit measures (e.g., boiler control, economizers, heat recovery, etc).

5.3 TECHNOLOGIES INCLUDED IN ECONOMIC POTENTIAL FORECAST

Exhibit 5.1 (below) provides a listing of the technologies selected for inclusion in this forecast. In each case, the exhibit shows the following:

- End use affected
- Upgrade measure(s) selected
- Sub sector(s) to which the measures were applied
- Rate at which the measures were introduced into the stock i.e., immediate or new installations or end-of-life replacement.

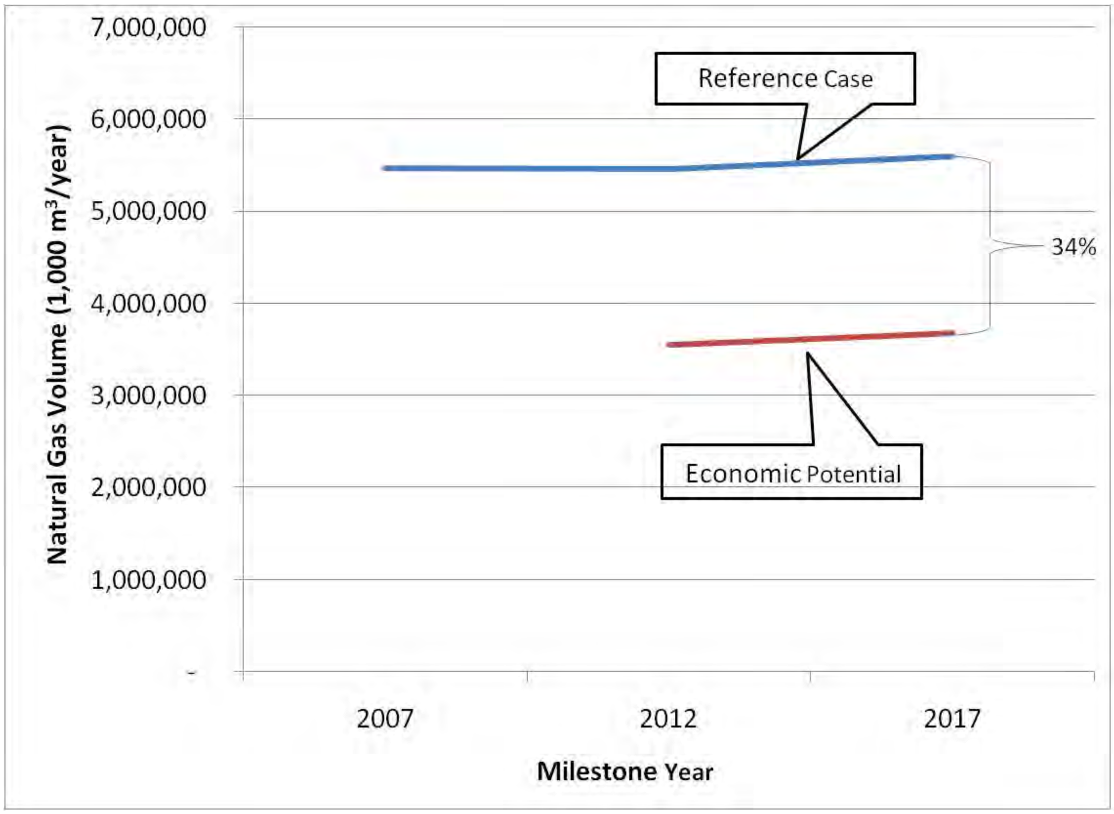
Exhibit 5.1: Technologies Included in Economic Potential Scenario Chemical Sub Sector

End Use	Measure	Applicability to Sub Sector	Rate of Introduction
System	Integrated control system	All	Immediate
	Sub-metering	All	Immediate
Hot Water Systems and Boilers Steam Systems	Economizer	All	Immediate
	Blowdown heat recovery	All	Immediate
	Boiler combustion air preheat	All	Immediate
	Process heat recovery to preheat make-up water	All	Immediate
	Condensing boiler	All	End-of-life/ New
	Direct contact hot water heaters	All	End-of-life/ New
	Boiler right sizing and load management	All	End-of-life/ New
	High-efficiency burners	All	Immediate
	Insulation	All	Immediate
	Advanced boiler controls	All	Immediate
	Blowdown control	All	Immediate
	Boiler water treatment	All	Immediate
	Boiler maintenance	All	Immediate
	Condensate return	All	Immediate
	Steam trap survey and repair	All	Immediate
	Instantaneous steam generation	All	Immediate
Process Heat (Furnace/ Kilns/ Ovens/ Dryers)	Exhaust gas heat recovery	All	Immediate
	High-efficiency burners and burner controls	All	Immediate
	Insulation	All	Immediate
	Advanced heating and process controls	All	Immediate
	High-efficiency ovens	Paper, Chemical, Transport & Machinery, Non-metallic Mineral, Misc., Food & Beverage	End-of-life/ New
	High-efficiency dryers	Paper, Chemical, Misc., Food & Beverage	End-of-life/ New
	High-efficiency kilns	Non-metallic Mineral	End-of-life/ New
	High-efficiency furnaces	Primary Metal, Transportation & Machinery, Non-metallic Mineral	End-of-life/ New
	Air curtains	All	Immediate
Other Process	Pollution control measures	Transportation & Machinery, Misc.	End-of-life/ New
	Hydrogen atmospheres for steel batch coil annealing	Misc.	Immediate
	Process Heat Recovery	All	Immediate
HVAC	Radiant heaters	All	Immediate
	Automated temperature control	All	Immediate
	Solar walls	All	Immediate
	Warehouse loading dock seals	All	Immediate
	Air curtains	All	Immediate
	Air compressor heat recovery	All	Immediate
	Destratification fans	All	Immediate

5.4 PRESENTATION OF RESULTS

Exhibit 5.2 compares the Reference Case and Economic Potential Forecast levels of industrial energy consumption. As illustrated, under the Reference Case industrial natural gas consumption would grow from the Base Year level of approximately 5,465 million m^3/year to 5,598 million m^3/year by 2017. This contrasts with the Economic Potential Forecast in which natural gas consumption would decrease to approximately 3,674 million m^3/year, a difference of approximately 1,924 million m^3/year, or 34% by 2017.

Exhibit 5.2: Reference Case versus Economic Potential - Natural Gas Consumption for the Total Union Gas Service Area (1000 m3/yr.)



5.4.1 Natural Gas Savings

Further detail on the total potential natural gas savings provided by the Economic Potential Forecast is provided in the following exhibits:

- Exhibits 5.3 and 5.4 present the results by sub sector, end use and milestone year for the total Union Gas Service Area.
- Exhibit 5.5 graphically presents the forecasted results in 2017 by sub sector and end use for the total Union Gas Service Area.

A detailed breakdown of the Economic Potential results by service region is presented in Appendix C.

Exhibit 5.3: Natural Gas Savings by Sub Sector and End Use for the Total Union Service Area in Milestone Year 2012 (1000 m^3/yr.)

Sub Sector	End Use							
	System	Hot Water Systems	Boiler Steam Systems	Process Direct Heat	Other Process	HVAC	Total	
Contract Primary Metal[73]	89,821	3,941	35,772	298,984	2,754	68,586	499,857	26%
Contract Chemical	76,884	3,339	100,384	97,179	9,011	66,722	353,519	19%
Other Chemical	693	30	905	876	81	601	3,187	0.2%
Contract Paper	25,007	1,232	59,602	20,533	824	20,622	127,820	7%
Contract Transportation and Machinery	27,783	1,357	24,369	32,283	1,898	55,312	143,002	8%
Other Transportation and Machinery	3,702	181	3,247	4,301	253	7,370	19,053	1.0%
Contract Petroleum Refineries	23,225	1,003	15,596	73,476	560	12,217	126,078	6.6%
Contract Mining	21,841	9,877	19,158	38,343	1,261	15,036	105,517	6%
Contract Food and Beverage	30,071	3,742	34,429	21,832	1,915	10,167	102,156	5%
Other Food and Beverage	1,919	239	2,197	1,393	122	649	6,518	0.3%
Contract Non-Metallic Mineral	19,862	891	8,347	86,400	1,215	10,966	127,681	7%
Miscellaneous Industrial	73,007	5,905	20,346	46,391	2,097	141,150	288,896	15%
Total	393,815	31,738	324,351	721,991	21,991	409,398	499,857	100%
Percentage of Total	21%	2%	17%	38%	1%	22%		

73 As highlighted in Section 2.3, an assessment of data obtained at the completion of this study indicated that up to about 42% of the Base Year natural gas consumption in the Contract Primary Metal sub sector could be considered as feedstock. It was not feasible to include the data in the study at this late stage of the study. The implication is that the energy efficiency potential in the Contract Primary Metal sub sector might be overstated.

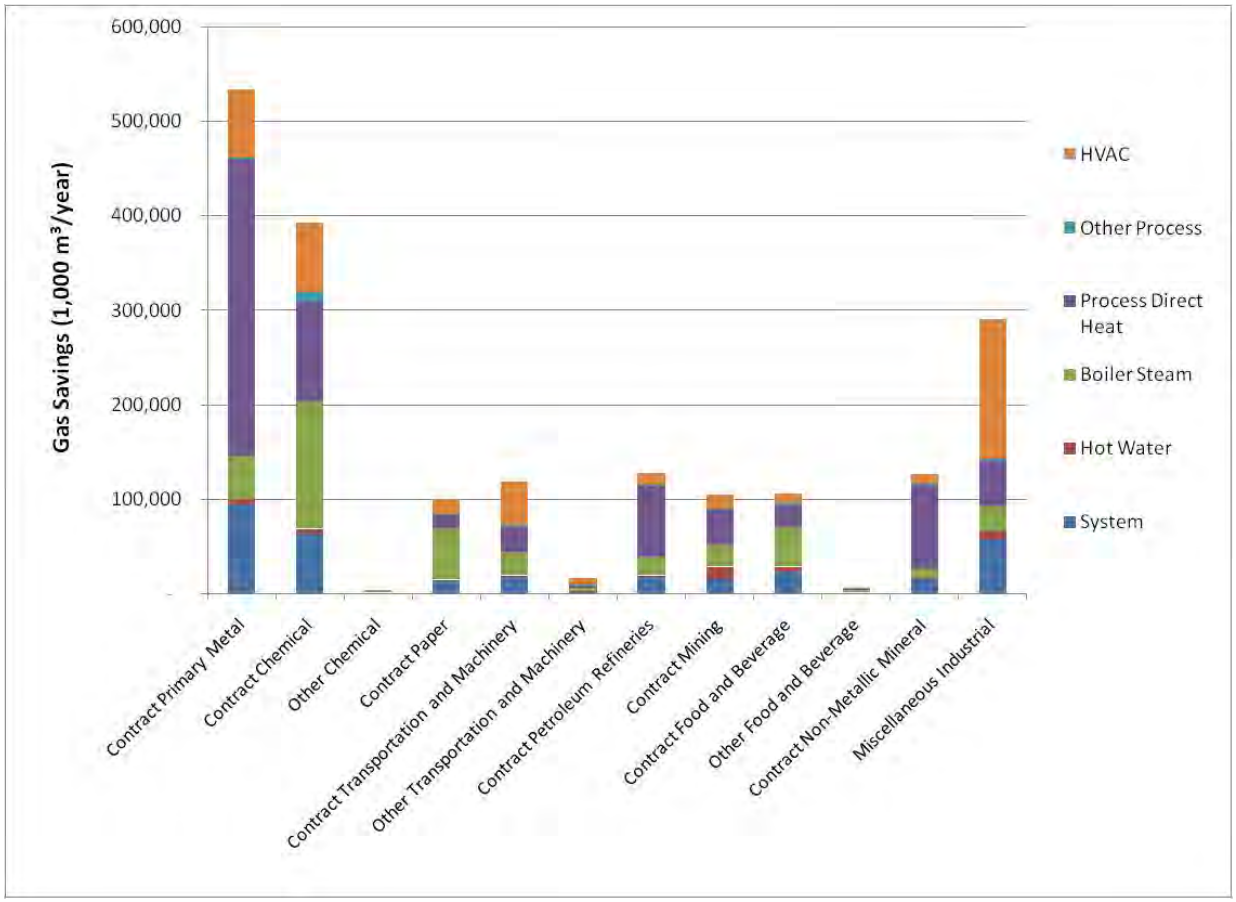
Exhibit 5.4: Natural Gas Savings by Sub Sector and End Use for the Total Union Service Area in Milestone Year 2017 (1000 m^3/yr.)

Sub Sector	End Use							
	System	Hot Water Systems	Boiler Steam Systems	Process Direct Heat	Other Process	HVAC	Total	
Contract Primary Metal	94,745	5,428	46,092	312,941	2,901	72,090	534,197	28%
Contract Chemical	63,733	4,721	134,508	106,478	9,948	73,407	392,796	20%
Other Chemical	687	43	1,212	960	90	662	3,653	0.2%
Contract Paper	13,809	1,162	53,732	15,011	607	15,133	99,455	5%
Contract Transportation and Machinery	17,508	1,423	24,547	26,972	1,593	46,028	118,071	6%
Other Transportation and Machinery	2,271	190	3,271	3,594	212	6,133	15,670	0.8%
Contract Petroleum Refineries	17,924	1,362	19,601	75,035	575	12,529	127,026	6.6%
Contract Mining	16,023	12,212	22,692	37,343	1,230	14,628	104,128	5%
Contract Food and Beverage	23,303	4,782	42,424	22,376	1,969	10,405	105,259	5%
Other Food and Beverage	910	305	2,707	1,428	126	664	6,140	0.3%
Contract Non-Metallic Mineral	15,168	1,150	10,292	87,681	1,236	11,110	126,638	7%
Miscellaneous Industrial	57,899	7,743	25,658	48,681	2,210	147,826	290,017	15%
Total	323,980	40,521	386,738	738,500	22,697	410,615	1,923,051	100%
Percentage of Total	17%	2%	20%	38%	1%	21%		

The results presented in the preceding exhibits highlight the following observation applicable to the savings by milestone year:

- Approximately 100% of the identified savings in 2017 were economically feasible by 2012. This is because most of the measures are cost effective at full cost, i.e., it is economically attractive to implement them before the equipment they affect or replace has reached the end of its useful life. Under the Economic Potential Forecast, they would therefore be implemented in the first milestone year.

Exhibit 5.5: Natural Gas Savings by Sub Sector and End Use for the Total Union Service Area in Milestone Year 2017 (1000 m^3/yr.)



Highlights of the results presented in the preceding exhibits are summarized below:

Savings by End Use

- Process direct heat (38%) and boiler steam system (20%) measures account for the largest share of the identified savings in 2017 for the total Union Service Area, followed by HVAC (21%).

Savings by Sub Sector

- Among modelled sub sectors in the Southern service region, the largest percentage of the identified savings in 2017 are in Contract Primary Metal (27%), Contract Chemical (19%) and Miscellaneous (21%).

- In the Northern service region, the Contract Primary Metal (30%) and Contract Chemical (25%) sub sectors again account for the largest share of the identified savings in 2017, followed by Contract Mining (18%) and Contract Paper (15%).

Savings by Service Region

As indicated above, the detailed Economic Potential Forecast results for the northern and southern service regions are presented in Appendix C.

- The Southern service region represents approximately 69% of the identified savings in 2017. This is to be expected given the larger volume of natural gas consumed by the Industrial sector in this service region.

5.5.1 Caveats on Interpretation of Results

A systems approach was used to model the energy impacts of the efficiency upgrades presented in the preceding section. In the absence of a systems approach, there would be double counting of savings and an accurate assessment of the total contribution of the energy-efficient upgrades would not be possible.

For example, advanced boiler controls reduce boiler natural gas use, as does the installation of high-efficiency burners. On its own, each measure will reduce overall boiler heating energy use. However, the two savings are not additive. The order in which some upgrades are introduced is also important. In this study, the approach has been to select and model the impact of measures that reduce the load for a given end use (e.g., boiler right sizing and load management) and then to introduce measures that meet the remaining load more efficiently (e.g., high-efficiency burner).

The above approach means that where there is interaction between measures that affect the same end use, the savings for those individual measures are reduced. As appropriate, this issue is addressed in the Achievable Potential section of this report.

6. ACHIEVABLE POTENTIAL FORECAST

6.1 INTRODUCTION

This section presents the Industrial sector Achievable Potential natural gas savings for the study period (2007 to 2017). The Achievable Potential is defined as the proportion of the gross savings identified in the Economic Potential Forecast that could realistically be achieved within the study period.

The discussion is organized into the following sub sections:

- Description of Achievable Potential
- Approach to the Estimation of Achievable Potential
- Achievable Potential Workshop Organization
- Achievable Potential Workshop Results
- Achievable Potential Results
- Summary and Interpretation of Results.

6.2 DESCRIPTION OF ACHIEVABLE POTENTIAL

Achievable Potential recognizes that it is difficult to induce all customers to purchase and install all of the energy-efficiency measures that meet the criteria defined by the Economic Potential Forecast presented in the preceding section.

Exhibit 6.1 illustrates the level of natural gas consumption estimated in the Achievable Potential scenarios. As illustrated in Exhibit 6.1, reductions in natural gas consumption under Achievable Potential are “banded” by the two forecasts presented in previous sections, namely the Reference Case and the Economic Potential Forecast.

Exhibit 6.1: Illustration of Achievable Potential versus Reference Case and Economic Potential Forecasts

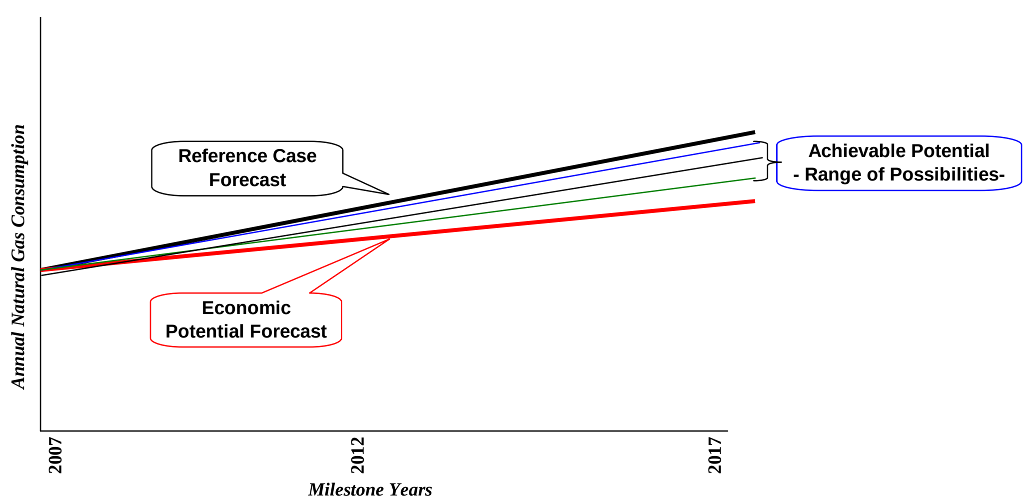


Exhibit 6.1 shows that future natural gas consumption under the Reference Case is greater than in any of the Achievable Potential forecasts. This is because the Reference Case represents a “worst case” situation in which there are no additional utility market interventions and hence no additional natural gas savings beyond those that occur “naturally.”

Exhibit 6.1 also shows that future natural gas consumption under the Achievable Potential is greater than in the Economic Potential Forecast. This is because the Economic Potential Forecast assumes that efficient new technologies fully penetrate the market as soon as it is cost effective to do so. However, the Achievable Potential recognizes that under “real world” conditions, the rate at which customers are likely to implement energy-efficiency measures will be influenced by market constraints and, as a result, implementation will occur more slowly than under the assumptions employed in the Economic Potential Forecast.

Exhibit 6.2 illustrates some of the types of market constraints that often affect customer implementation of energy-efficiency measures.

Exhibit 6.2: Illustration of “Typical” Market Constraints Affecting Energy-efficiency (EE) Implementation

Category	Barrier
Price Signals	• No monetization of externalities • Tax and subsidies that affect the playing field between EE and the fuels being displaced
Customer EE Awareness	• Awareness that EE opportunities and products exist • Awareness of benefits – cost and co-benefits • Customers’ technical ability to assess the options
Product and Service Availability	• Local or national product availability • Existence of a viable infrastructure of trade allies • Vendor or trade ally awareness of the efficiency options and their understanding of the technical issues
Financing of EE Measures	• Access to appropriate financing • Size of required EE investment vs. asset base • Payback ratio – actual vs. required
Transaction Costs	• Level of effort/hassle required to become informed, select products, choose contractor(s) and install
Perceived Risk/Reward	• Level of perceived risk that the EE product may not perform as promised • Level of positive external/personal recognition for “doing the right thing” by installing the EE measure(s)
Split Incentive/Motivation	• Level to which the incentives of the agent charged with purchasing the EE are aligned with those of the person(s) that would benefit
Regulatory	• Codes or standards that prohibit implementation of innovative EE technologies • Level of EE performance that is required in codes or standards

The Achievable Potential scenarios shown in Exhibit 6.1 are presented as a range. This recognizes not only that any estimate of Achievable Potential over a 10-year period is necessarily subject to uncertainty but also that there are different types and levels of potential DSM program intervention. Government and utility DSM program experience throughout North America has shown that energy-efficiency market barriers can be addressed and customer willingness to accept and purchase energy-efficient products can be positively influenced by a variety of potential DSM market intervention strategies, such as those noted below in Exhibit 6.3.

The same body of DSM program experience also recognizes that there are limits to a utility's scope of influence. It recognizes that some markets or sub markets may be so price sensitive or constrained by market barriers beyond the influence of utility DSM programs that they will only fully act if forced to by legal or other legislative means. It also recognizes that there are practical constraints related to the pace that existing inefficient equipment can be replaced by new, more efficient models or that existing building stock can be retrofitted to new energy performance levels. In addition, the design and implementation of DSM market interventions, such as those noted in Exhibit 6.3, require staff and financial resources. Under "real world" conditions these resources are also subject to constraints.

Exhibit 6.3: "Illustration" of Potential DSM Market Intervention Strategies[74]

Strategy Type	Description
Alliances	• Vertical integration of market between upstream and downstream market actors (i.e., forming a relationship between contractors and suppliers)
Audit	• An assessment of a building's energy efficiency made by a trained inspector
Contractor Certification	• An assurance that a given contractor is knowledgeable about the product or service, verified through training and/or testing
Demonstration	• Providing demonstrations of the use/performance of energy-efficient technologies to market actors
Design Assistance	• Providing recommendations on building or product design.
Financing	• Providing loans to finance the acquisition of a product or service.
Financial Incentives (and Rebates)	• Per measure dollars provided to market participants (generally either end users or distribution channel members) to encourage energy conservation measure installation
Information	• Passive provision of information to market participants
Linking Vendors & Customers	• Providing customer contacts to contractors, or contractor/vendor contacts to customers
Non-Financial Incentives	• Products, changes in procedures or administrative consolidation to encourage product or service provision
Promotion	• Active advertising and information made available to the market
Sales Training	• Providing sales, marketing and/or technical training about products or services to individuals responsible for selling it
Standards, Labelling	• Setting specific standard levels for energy-efficient technologies • Labelling those technologies accurately for easy consumer/contractor recognition
Technical Information	• Provision of technical information on energy-efficient products or services
Technical Support	• Providing answers to technical questions from market actors about energy-efficient products/services after installation
Technical Training	• Providing training to trade allies so that they better understand new or existing practices or procedures
Testing Protocols & Standards	• Standardization of testing protocols for installation and repair
Third Party Verification	• Inspection and verification provided by an unbiased party on the results of an inspection to insure correct product or service performance

Source: American Council for an Energy Efficient Economy (ACEEE) Proceedings: 2001.

[74] As in the preceding Exhibit, the strategies shown in Exhibit 6.3 are not necessarily exhaustive; rather, they illustrate the types of options that may be available to DSM program planners.

6.3 APPROACH TO THE ESTIMATION OF ACHIEVABLE POTENTIAL

Consistent with the description outlined above, this study approached the estimation of Achievable Potential by preparing a number of future scenarios, each representing differing assumptions related to the level of DSM program investment over the study period.

In consultation with Union personnel, the study identified two Achievable Potential scenarios to be assessed in this final stage of the study.[75] They are:

- A financially unconstrained DSM investment scenario
- A financially constrained DSM investment scenario, based on the maintenance of historic Union DSM program funding levels.

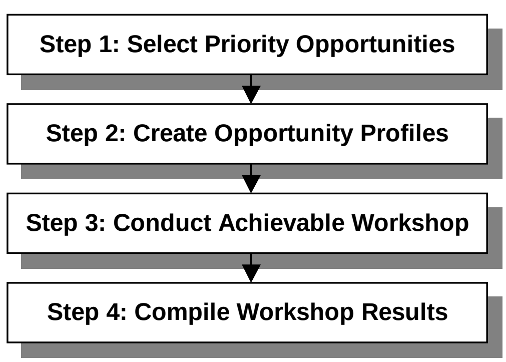
Development of the assumptions employed in each of the above scenarios was based on a combination of Union's own DSM program experience and the results of a one-day workshop involving Union DSM personnel, trade allies and consultant team members.

The workshop results were particularly valuable in generating the DSM investment scenarios; consequently, a brief description of the workshop organization and results is provided in the following sections.

6.4 ACHIEVABLE POTENTIAL WORKSHOP ORGANIZATION

The design and implementation of the Achievable Potential workshop was organized into four steps. A schematic showing the major steps is shown in Exhibit 6.4 and each step is briefly discussed below.

Exhibit 6.4: Approach to Achievable Potential Workshop



Step 1: Select Priority Opportunities

The first step was to review the energy saving opportunities identified in the Economic Potential Forecast and to select a set of those opportunities for discussion in the Achievable Potential workshop. The amount of time available in the Achievable Potential workshop for the discussion

[75] It should be emphasized that the estimation of Achievable Potential scenarios is not synonymous with either the setting of specific program targets or with program design. While both are closely linked to the discussion of Achievable Potential, they involve more detailed analysis that is beyond the scope of this study.

of energy-efficiency opportunities was limited. Consequently, the number of opportunities selected for discussion in the workshop was limited to seven, which prior experience had shown to be about the maximum allowable within the available timeframe.

Exhibit 6.5 shows the six energy-efficiency measures and the one assessment opportunity (namely process integration and pinch analysis) selected for inclusion in the workshop discussions. Selection of the opportunities was based on a qualitative application of criteria that were intended to ensure that the workshop discussions would include:

- Technologies and measures that represent a significant share of the potential energy savings identified in the Economic Potential Forecast
- Review of conditions in a variety of sub markets
- Inclusion of new products or markets where little prior DSM experience existed
- Tools that can be used to increase participation rates of energy-efficiency opportunities.

Exhibit 6.5: Industrial Sector Opportunity Areas

Opportunity Area	Title	Approximate % of Economic Savings Potential
I1	Steam Trap Survey & Repair	3.6%
I2	High-efficiency Burners & Burner Controls	4.8%
I3	High-efficiency Ovens	4.8%
I4	Economizer	2.8%
I5	Process Heat Recovery	7.0%
I6	First Generation Super Boilers	N/A
I7	Process Integration and Pinch Analysis	N/A
	Total	23%

Step 2: Create Opportunity Profiles

Brief profiles were prepared for each Opportunity selected in Step 1. The profiles, which were used to introduce the workshop discussion of each opportunity and can be found in Appendix E, provided the following information:

- **Technology description**, e.g., regular steam trap survey and repair of faulty steam traps

- **Sub sector and service region**, e.g. applicable to all industrial sub sectors, because all sub sectors have steam distribution systems

- **Selection of a "Typical" application** for discussion purposes

- **Financial and economic indicators for the "Typical" application**, e.g., installed cost, useful life, annual energy savings simple payback, benefit/cost ratio, basis of assessment (incremental versus full cost)

Exhibit 6.6 (overleaf) lists the steps employed in developing the estimated participation rates.

Exhibit 6.6: Workshop Process for Estimating Participation Rates

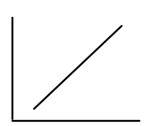
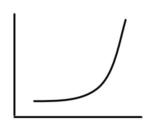
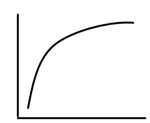
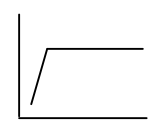
The steps involved were as follows:

The participation rate for the Aggressive Marketing scenario in 2017 was estimated.

The shape of the adoption curve was selected for the Aggressive Marketing scenario. Rather than seek consensus on the specific values to be employed in each of the intervening years, workshop participants selected one of four curve shapes that best matched their view of the appropriate “ramp-up” rate for each opportunity (see below).

The preceding process was repeated for the Static Marketing scenario.

Once participation rates had been established for the specific technology, sub sector and service region selected for the Opportunity discussion, the workshop participants provided guidelines to the consultants for extrapolating the discussion results to the other sub sectors and service regions included in the Opportunity, but not discussed in detail during the workshop

Curve A	Curve B	Curve C	Curve D
			

Curve A represents a steady increase in the expected participation rate over the 10-year study period

Curve B represents a relatively slow participation rate during the first half of the 10-year study period followed by a rapid growth in participation during the second half of the 10-year study period

Curve C represents a rapid initial participation rate followed by a relatively slow growth in participation during the remainder of the 10-year study period

Curve D represents a very rapid initial participation rate that results in virtual full saturation of the applicable market during the first milestone period of the 10-year study period.

Step 4: Compile Workshop Results

This step involved aggregating the results of the seven Opportunities discussed during the workshop and extrapolating the results of the remaining Opportunities that were identified in the Economic Potential Forecast but not discussed during the workshop.

6.5 ACHIEVABLE POTENTIAL WORKSHOP RESULTS

The following discussion provides a summary of the workshop results for each of the Industrial sector Opportunities noted previously in Exhibit 6.5. In each case, the following information is provided:

- Brief description of the Opportunity and the specific "typical" application selected for the workshop discussion

  - Highlights from the workshop discussions related to:
    - Constraints & Challenges
    - Potential Strategies and Partners
    - Incentive Sensitivity

- Summary of the estimated participation rates under the Aggressive and Static Marketing scenarios for the selected sub sector

    - Shape of Adoption Curve selected by the workshop participants

- Summary of major assumptions employed by the consultants for extrapolating the workshop results to other sub sectors.

6.5.1 I1 - Steam Trap Survey & Repair

- **Description**

  - If the traps do not function properly, excess steam will flow through the end-use device or the condensate will back up into it
  - Traps provide for condensate removal with little or no steam loss
  - For discussion purposes the workshop focused on full cost (retrofit) applications in the Food sub sector (small, medium and large).

- **Discussion Highlights**

Constraints & Challenges

- There are two components to this measure: the audit/assessment and the replacement. Consideration needs to be given to decide how much of the cost assigned to this measure is for the assessment and how much is for the actual repairs, as the audit might be done every three years, but the replacement is not likely to happen as frequently.
- The main impediment to having this measure implemented is the cost of paying for the actual survey of the steam traps.
- The willingness to do the surveys is increasing, but it is difficult to convince plants to actually do the repairs. Experience indicates that the audit may identify the same faults, but the repairs are not done. There might be a technical reason why the repairs are not done, but it is often due to a lack of internal resources.
- Maintenance is stretched thin and generally only major repairs are done. If steam traps are not considered a top priority, then repairs might not be undertaken.

- Plant culture is more imposing than plant size in deciding whether or not to implement this measure.
- Other technologies might begin to replace this measure. For example high-pressure water could be returned to tanks.
- Large customers have more steam pressure, so they have higher losses, but still do not perform the repairs.

Potential Strategies and Partners

- Similar to the air leaks problem, if this measure is promoted as part of a repair program, rather than a one-off repair, it is more successful.
- Feedback is needed for how the plant runs when this repair is made and when nothing is done. For example, installing a thermocouple on the steam vent can identify how much energy is being lost to steam venting.
- Looking at the cumulative effect of all of the small leaks can help to increase the value of performing this measure.
- Savings are often compared to total sales, but are more appropriately/ effectively compared to profit.
- There are two parts to deciding whether to perform this measure, payback period and total capital cost.
- In promoting the program, need to talk to not only the plant manager, but also the maintenance manager.
- The programs that are most successful include a link to implementation and are not limited to the audit. For example, a facility needs to implement all measures that meet certain criteria in order to receive the incentive for the audit portion. However, this link might also discourage some plants from performing the audit, which would be detrimental, as it is very useful to have the audit performed.
- A need for more specialized people to identify opportunities was expressed.

Incentive Sensitivity

- This measure is very sensitive to incentive levels.
- Incentives would have to be rather large in order to increase the uptake of this measure (at least 30%). At 10%, there would not be many new plants implementing this measure. The offer of 30% will provide an opportunity to communicate with the facility, but it is important to target the right audience.
- Incentives have less effect on sectors with higher pressures because the losses are much higher as well.

❑ Participation Rates

Workshop participants concluded that, under the conditions represented by the Aggressive Marketing scenario, a participation rate of 20% to 30% of the remaining eligible plants could be achieved in the Food sub sector by 2017. It was also decided that a steadily increasing curve, curve A, represents the most likely adoption profile.

Under the more modest market conditions represented by the Static Marketing scenario, it was estimated that participation rate would be lower, at about 5% to 15% of the remaining eligible plants. A similar adoption curve would be followed in this case.

- **Participation Rates in Remaining Sub Sectors**

Based on the workshop discussions, it was estimated that participation rates would be slightly higher in the Primary Metal, Chemical, Paper, and Petroleum Refinery sub sectors, but approximately the same in all other sub sectors.

6.5.2 I2 - High-efficiency Burners and Burner Controls

- **Description**

- Efficient burner technology based on design and power injection to optimize fuel-air ratio throughout firing range
- Boiler controls include linkage-less controls and servomotors to independently control the fuel and air, and combustion control based on flue gas monitoring
- For discussion purposes the workshop focused on full cost (retrofit) applications in the Food sub sector (small, medium and large).

- **Discussion Highlights**

Constraints & Challenges
- Savings claims might not always be realistic and in plants where the demand is constant, controls may not have significant savings potential
- Many linkage-less controls options are available, each with different savings potential and compatibility issues
- Engineering costs might have to be included to verify expected achievable savings.
- It is not often that this measure is considered, mainly due to uncertainty related to results
- Even if all eligible sites implement this measure, the total savings might not be anywhere near the estimated total because of the variability of boiler conditions
- Some sites might implement a linkage-less control system, regardless of whether or not that is what they need, because that is all that is available.

Potential Strategies and Partners
- Customers might be receptive to early stage guidance. There are many claims about potential savings, but there is limited evidence. It is possible that the burner is not physically able to do what the controls are set to
- Linkage-less controls should not be recommended without first doing a detailed assessment. There might also be better options available, depending on the boiler
- Because this measure is very site specific, this measure would not work on its own, but could be included in a package of possible measures that would be evaluated on a site-by-site basis.

Incentive Sensitivity
- Meters are somewhat sensitive to incentives, but controls and replacements are not
- Knowledge is more important than incentive in this case because the payback period is already very short. It was proposed that a Union program should inform clients of the availability of higher-efficiency boilers and controls.

- **Participation Rates**

There is more potential for replacing controls than there is for replacing the actual burner. There would also be higher uptake on larger boilers than on smaller boilers.

Workshop participants concluded that, under the conditions represented by the Aggressive Marketing scenario, a participation rate in the range of 80% of the remaining eligible plants could be achieved in the Food sub sector by 2017. It was also decided that curve D, which represents a very rapid initial participation rate that results in virtual full saturation of the applicable market during the first milestone period of the 10-year study period, represents the most likely adoption profile.

For smaller boilers, the uptake for controls was estimated to be only about 50% to 70% of the remaining eligible plants over 10 years, and only about 10% to 15% of the remaining eligible plants for oxygen-trim systems, under the Aggressive Marketing scenario.

Under the more modest market conditions represented by the Static Marketing scenario, it was estimated that the participation rate would be much lower, at about 25% of the remaining eligible plants. Curve C, which represents a rapid initial participation rate followed by a relatively slow growth in participation during the remainder of the 10-year study period, was selected as the most likely adoption profile.

- **Participation Rates in Remaining Sub Sectors**

Based on the workshop discussions, it was estimated that participation rates would be slightly lower in the Primary Metal sub sectors, and almost non-existent in Petroleum Refineries, but approximately the same in all other sub sectors.

6.5.3 I3 - High-efficiency Ovens

- **Description**

- Advances in oven energy efficiency are primarily related to improved control systems, improved combustion efficiency, reduced energy losses, optimize uniform heating and reclaiming heat from exhaust gas
- For discussion purposes the workshop focused on full cost (retrofit) applications in the Food sub sector (small, medium and large).

- **Discussion Highlights**

Constraints & Challenges
- It is very unlikely that there would be many, if any, end-of-life replacements in the next 10 years. To fully replace an oven would normally require that the plant be shut down during the replacement. The general practice is to make as many retrofits as possible before a complete replacement
- One of the barriers to installation would be the fact that changing the oven would affect the production process. Also, food ovens, in general, have little room for improvement because of the nature of the process

- Most improvements that could be made would be process and not equipment improvements
- A high level of understanding of the process is required before changes can be made.

Potential Strategies and Partners

- One may be able to make a business case for the replacement of an oven by also considering savings from increased productivity. Energy savings are generally the minor part of the decision making
- Participants indicated that there is significantly more room for improvement in upgrading furnaces compared to ovens
- Higher-temperature ovens have a much greater opportunity for improvement. Once again, retrofits would be done, but not normally replacements
- There might be more potential in small continuous ovens, as there has not been much pressure to upgrade.

Incentive Sensitivity

- Plants are either new and in good shape, or so old that there is high risk with changing the process and there might also be a chance that the plant will close. Having an incentive might open the door for discussion, but will not significantly affect the decision. This makes this measure somewhat insensitive to incentives.

- **Participation Rates**

In the food and beverage industry, there are not likely to be many replacements but there is a potential for retrofits.

- **Participation Rates in Remaining Sub Sectors**

There might be more opportunities for replacement in industries with paint ovens. About half of the existing market is already high-efficiency (paint ovens), while ovens in the automotive and the rubber and plastic industries have room for improvement.

6.5.4 I4 - Economizer

- **Description**

- Heat exchanger that is designed to use heat from hot boiler flue gases to preheat water
- A condensing economizer improves the effectiveness of reclaiming flue gas heat by cooling the flue gas below the dew point
- For discussion purposes, the workshop focused on full cost (retrofit) applications in the Food sub sector (small, medium and large).

- **Discussion Highlights**

Constraints & Challenges

- Need to have a heat sink to transfer the recuperated heat

- Water treatment can result in a very high pH, which may corrode the economizer
- Average life of both standard and condensing economizers is about 10 years. There might be some backlash in a few years if there is a high failure rate of the units due to corrosion
- Large civil work may be required for the installation of a condensing economizer as it can be very heavy and may require large reinforcements. This may increase the costs significantly
- Mostly applicable to medium and large boilers. Less applicable to HVAC boilers.

Potential Strategies and Partners

- Economizers have become more economical as energy prices have risen and smaller, lighter and more durable economizers have been developed
- There is significant interest in moving from standard to condensing economizers.

Incentive Sensitivity

- Economizer projects with a long payback period would make this measure somewhat sensitive to incentive levels.

❑ **Participation Rates**

Workshop participants concluded that, under the conditions represented by the Aggressive Marketing scenario, a participation rate of about 75% of the remaining eligible pool of participants in the Food sub sector could be obtained by 2017. Adoption profile curve B was selected, which represents a relatively slow participation rate during the first half of the 10-year study period followed by a rapid growth in participation during the second half of the 10-year study period.

Under the more modest market conditions represented by the Static Marketing scenario, it was estimated that the participation rate would be lower, at about 35% of the remaining eligible market. A similar adoption curve would be followed in this case.

❑ **Participation Rates in Remaining Sub Sectors**

Based on the workshop discussions, it was decided that participation rates would be approximately the same across all Industrial sub sectors.

6.5.5 I5 - Process Heat Recovery

❑ **Description**

- The use of waste heat from industrial processes (heat source) to heat other processes, or utility streams (heat sink)
- Depends on quality of the heat (high- or low-grade heat), the distance between the heat source and heat sink, potential cross contamination of product, properties of the process stream (such as corrosiveness), the flow rates of the streams and the fluctuation in the flow rates

- For discussion purposes, the workshop focused on full cost (retrofit) applications in the Chemical sub sector (small, medium and large).

Discussion Highlights

Constraints & Challenges

- The practical potential and feasibility of heat recovery is very dependent on the type of heat source and heat sink, and there is a big difference between air-to-air and fluid-to-fluid heat recovery. The latter has much higher potential
- General constraints include contamination; corrosion and space availability
- Constraints for low-grade heat opportunities include payback period and finding a good heat sink
- It is not always easy to make the business case for heat recovery projects. One may have to model the process in order to determine the possible benefits and one may also require meters to quantify the potential
- Plants may not have the technical capability to initiate or assess heat recovery projects
- Plants may lack knowledge of the types of heat exchangers available and the technical feasibility of the heat exchangers
- Human and capital resource constraints were identified as a constraint.

Potential Strategies and Partners

- A need was identified to have qualified engineering firms undertaking these projects. The concern was expressed that the available firms provide too many options and may not target low-grade heat.
- It was observed that the main project drivers are generally not savings, but rather increased comfort (especially for low-grade heat)
- Other opportunities could be in latent heat recovery (3- to 6-year payback), poly-socks and HVAC makeup air

Incentive Sensitivity

- Low-grade heat opportunities are incentive sensitive, but increasing the incentive will not necessarily increase the market take-up proportionally.

- **Participation Rates**

Workshop participants concluded that, under the conditions represented by the Aggressive Marketing scenario, a participation rate of an additional 30% to 40% of the eligible sites could be achieved in the Chemical sub sector by 2017. It was also decided that a steadily increasing curve, curve A, represents the most likely adoption profile.

Under the more modest market conditions represented by the Static Marketing scenario, it was estimated that the participation rate would be slightly lower, at about 15% to 20% for high-grade heat projects, and 10% for low-grade heat projects. A similar adoption curve would be followed in both of these cases.

- **Participation Rates in Remaining Sub Sectors**

Based on the workshop discussions, it was decided that for high-grade heat projects participation rates would be slightly higher in the Primary Metal and Mining sub sectors and lower in the Paper, Transportation and Machinery and Food and Beverage sub sectors. For low-grade heat projects, participation rates would be slightly higher in the Transportation and Machinery and Food and Beverage sub-sectors, and non-existent in Non-Metallic Mineral and Miscellaneous Industry subsectors.

6.5.6 I6 - First Generation Super Boilers

- **Description**

- Two-stage fire tube design and a transport membrane condenser and compact air heater
- Also includes compact convective zones with intensive heat transfer and a staged/intercooled combustion system for ultra-low emissions
- Currently in the early stages of commercialization
- For discussion purposes, the workshop focused on incremental cost (end-of-life) applications in the Food sub sector (small, medium and large).

- **Discussion Highlights**

Constraints & Challenges

- One constraint to the implementation of this technology is whether or not the plant employs a boiler operating engineer. Some plants may not be willing/ able to install a large boiler because that would require having an operating engineer
- This technology is very expensive relative to the existing technology and very high risk. Competing technologies would restrict the uptake of this measure
- Good potential program target because the benefit-cost ratio is good, but the payback period is very long
- The efficiency of this boiler is comparable to a boiler with a condensing economizer
- Cogeneration might also compete with this technology.

Potential Strategies and Partners

- This technology is to be included in the study as an advanced technology opportunity, and should not be included as a measure.

Incentive Sensitivity

- Boiler will most likely only be installed as part of a demonstration project.

- **Participation Rates**

Other than a potential demonstration project, there is not likely to be a boiler installed in any sub sector.

6.5.7 I7 - Process Integration and Pinch Analysis

- **Description**

- Systematic and methodical techniques for designing a process and/or appropriate heat exchanger network to optimize industrial processes involving heat transfer between either process streams or between a utility stream and a process stream
- Pinch analysis involves calculating thermodynamically attainable energy targets for a given process and then identifying how to achieve them
- For discussion purposes the workshop focused on full cost (retrofit) applications in the Food sub sector (large).

- **Discussion Highlights**

Constraints & Challenges

- The opportunities identified are generally good, but it takes a long time before projects are actually implemented
- Delegates regarded pinch analysis as overly complicated and expensive
- There is insufficient expertise in Ontario to perform pinch and process integration analysis
- Pinch analysis is generally not suitable for smaller plants. The same result could be attained by simply listing the heat supplies and sinks and matching them up. Process integration might be more applicable.

Potential Strategies and Partners

- Need to identify local expertise that is able to perform these studies more efficiently and for less
- These measures should be lumped in with measurement and targeting.

- Participation Rates

Workshop participants concluded that, under the conditions represented by the Aggressive Marketing scenario, a participation rate up to 75% of the remaining eligible plants could be achieved in the Food sub sector by 2017. Small and medium plants would have lower take-up rates than larger plants. It was also decided that a steadily increasing curve, curve A, represents the most likely adoption profile.

Under the more modest market conditions represented by the Static Marketing scenario, it was estimated that the participation rate would be much lower, at about 25% of the remaining eligible plants. A similar adoption curve would be followed in this case.

- **Participation Rates in Remaining Sub Sectors**

  Based on the workshop discussions, it was decided that participation rates would be slightly higher in the Primary Metal, Chemical and Mining sub sectors and lower in the Transportation and Machinery and Non-Metallic Mineral sub sectors. It was estimated that little or no opportunity remains in the Petroleum Refinery or Paper sub sectors as these industries have already performed process integration in their plants.

6.5.8 Extrapolated Participation Rates for Remaining Opportunities

As noted previously, the workshop results were used as a reference point. This knowledge was combined with follow-up discussions with some of the workshop participants and consultant experience to estimate participation rates for the remaining energy-efficiency opportunities that are contained in the Economic Potential Forecast. The extrapolated participation rates are summarized in Exhibits 6.8 and 6.15, which are presented in Section 6.6.

6.6 ACHIEVABLE POTENTIAL DSM INVESTMENT SCENARIO RESULTS

Consistent with the description presented earlier in this section, the Achievable Potential results are presented as a range, which is defined by the following two scenarios:

- A “Financially Unconstrained” scenario, in which potential is limited by market constraints but not by program budget.

- A “Static Marketing” scenario, in which potential is limited by market constraints as well as DSM program budgets that are approximately similar to current Union levels (although the specific programs and technologies addressed would not necessarily be the same).

In order to facilitate the modeling of the Achievable Potential scenario, measures were grouped in “bundles.” In the Industrial sector, most programs are not offered on a measure-by-measure basis, but rather on a system or custom basis. Fifteen bundles were created to group measures together that logically fall into the same custom type of projects. The 15 bundles provide a manageable data set to be modeled and provide the level of accuracy required for the study to simulate typical concept program subsets. The bundles are listed in Exhibit 6.7.

Exhibit 6.7: Measure Bundles

End Use	Bundle	Measure
System	1	Sub-metering
	2	Integrated control system
Hot Water Systems and Boiler Steam Systems	3	Process heat recovery to preheat make-up water
		Boiler combustion air preheat
		Minimize deaerator vent losses
		Blowdown heat recovery
		Blowdown control
		Boiler water treatment
		High-efficiency burners
		Advanced boiler controls
		Economizer
	4	Boiler right sizing and load management
	5	Steam trap survey and repair
	6	Condensate return
	7	Insulation
	8	Boiler maintenance
	9	Condensing boiler
		Direct contact hot water heaters
		Instantaneous steam generation
Process Heat (Furnace/ Kilns/ Ovens/ Dryers)	10	Exhaust gas heat recovery
		High-efficiency burners and burner controls
		Insulation
		Advanced heating and process controls
		Air curtains
	11	High-efficiency ovens
		High-efficiency dryers
		High-efficiency kilns
		High-efficiency Furnaces
Other Process	12	Process heat recovery
	13	Pollution control measures
		Hydrogen atmospheres for steel batch coil annealing
HVAC	14	Radiant heaters
		Automated temperature control
		Solar walls
		Warehouse loading dock seals
		Air curtains
		Air compressor heat recovery
		Destratification fans
	15	Ventilation & heat recovery optimization

The results of each achievable scenario are presented below.

6.6.2 Financially Unconstrained DSM Investment Scenario

The financially unconstrained investment scenario provides an overview of the level of potential natural gas savings that could be achieved if a comprehensive portfolio of DSM programs was launched without any constraint on the availability of program funding. This scenario is based largely on the results of the Aggressive Marketing scenario that was explored during the Achievable Potential workshop.

Although the results of this scenario are not constrained by program funding, the results do incorporate consideration of the market constraints identified during the Achievable Potential workshop (see Exhibit 6.2), such as product and service availability, customer transaction costs, etc.

This scenario, therefore, provides a 'high level' estimate of the upper level of natural gas savings that could be achieved by Union's industrial customers over the nine-year period beginning in 2009 and ending in 2017. It also provides Union's industrial DSM program personnel with a view of the relative potential contribution of individual sub sectors, end uses, technologies and service regions.

Major Assumptions: Financially Unconstrained Scenario

- All measures that pass the measure TRC screen are included
- No program financial limit is set, except that all measures must continue to pass the measure TRC screen
- Participation rates are constrained by the market barriers noted in the workshop
- Participation rates for measures discussed in the workshop are employed directly and are shown in Exhibit 6.8
- Participation rates for the remaining measures are extrapolated from the workshop results and/or consultant experience and are shown in Exhibit 6.8

Fixed program costs (e.g., advertising, training workshops, contractor certification, etc.) and incentive costs are included for each measure. The levels selected for the scenario are summarized in Exhibit 6.9. In each case, the values shown draw on theworkshop results and recent Union DSM program experience.

Exhibit 6.8: Participation Rates for Financially Unconstrained Scenario

Workshop Reference Number	Upgrade Technology/Measure	Participation Rates in 2017 (% of eligible)			Adoption Curve Shape	Notes
		Small	Medium	Large		
	Integrated control system	28-88%	28-88%	35-95%	C	Based on workshop ref. I2
	Sub-metering	60%	60%	60%	C	Based on workshop ref. I2
I4	Economizer	86%	87%	90%	B	Based on workshop ref. I4
	Blowdown heat recovery	34-37%	39-42%	45-48%	B	Based on workshop ref. I4
	Boiler combustion air preheat	0-3%	0-27%	22-72%	B	Based on workshop ref. I5
	Process heat recovery to preheat make-up water	15%	17%	21%	A	Based on workshop ref. I1
	Condensing boiler	25-28%	25-28%	20-25%	B	Based on workshop ref. I5
	Direct contact hot water heaters	20%	20%	0%	A	Based on workshop ref. I1
	Boiler right sizing and load management	58-60%	60%	63%	A	Based on consultant experience
	High-efficiency burners	80-99%	82-100%	85-100%	C	Based on workshop ref. I2
	Insulation (boiler system)	80%	80%	85%	A	Based on workshop ref. I1
	Advanced boiler controls	70-80%	73-90%	82-96%	C	Based on workshop ref. I2
	Blowdown control	16%	16%	26%	A	Based on workshop ref. I1
	Boiler water treatment	69-74%	72-80%	79-84%	A	Based on workshop ref. I1
	Boiler maintenance	82%	87%	98%	A	Based on workshop ref. I1
	Minimize deaerator vent losses	82%	87%	98%	B	Based on workshop ref. I4
	Condensate return	58%	60%	62%	A	Based on workshop ref. I1
I1	Steam trap survey and repair	75%	80%	85%	A	Based on workshop ref. I1
	Instantaneous steam generation	89%	69%	0%	C	Based on consultant experience
	Exhaust gas heat recovery	52-74%	55-76%	60-82%	A	Based on workshop ref. I1
I2	High-efficiency burners and burner controls	64-72%	70-82%	74-84%	C	Based on workshop ref. I2
	Insulation (process heat system)	85%	85%	85%	A	Based on workshop ref. I1
	Advanced heating and process controls	50-60%	52-62%	55-64%	C	Based on workshop ref. I2
I3	High-efficiency ovens	51-62%	36-67%	58-72%	C	Based on workshop ref. I3
	High-efficiency dryers	51-62%	36-67%	58-72%	C	Based on workshop ref. I3
	High-efficiency kilns	0-50%	0-53%	0-56%	C	Based on workshop ref. I3
	High-efficiency furnaces	0-50%	0-53%	0-56%	C	Based on workshop ref. I3
	Air curtains (process heat system)	5%	6%	7%	C	Based on consultant experience
	Pollution control measures	0-20%	0-20%	0-36%	C	Based on consultant experience
	Hydrogen atmospheres for steel batch coil annealing	0-59%	0-63%	0%	A	Based on workshop ref. I5
I5	Process heat recovery	57-79%	60-81%	65-87%	A	Based on workshop ref. I5
	Radiant heaters	49%	51%	54%	A	Based on workshop ref. I5
	Automated temperature control	60%	60%	60%	C	Based on workshop ref. I2
	Solar walls	0%	2%	2-4%	A	Based on consultant experience
	Ventilation & heat recovery optimization	34-44%	46-47%	49%	B	Based on consultant experience
	Warehouse loading dock seals	60%	60%	60%	A	Based on workshop ref. I1
	Air curtains (HVAC)	81%	81%	81%	A	Based on workshop ref. I1
	Air compressor heat recovery	22-25%	24-27%	25-29%	A	Based on workshop ref. I5
	Destratification fans	15%	15%	20%	C	Based on consultant experience

Exhibit 6.9: Summary of Program Cost Assumptions – Financially Unconstrained Scenario[76]

End Use	Bundle	Fixed Program Costs ($/yr.)	Incentive Level *(% of installed cost)*	Payback After Incentive (yrs)
System	1	105,000	5.0%	0.5
	2	60,000	15.0%	0.2
Boilers	3	120,000	22.5%	1.6
	4	40,000	N/A-Fixed Incentive	0.04
	5	50,000	30.0%	0.6
	6	30,000	30.0%	3.1
	7	30,000	15.0%	0.6
	8	30,000	N/A-Fixed Incentive	0.3
	9	60,000	9.6%	0.3
Process Heat	10	130,000	15.0%	0.7
	11	180,000	15.0%	0.7
Other Process	12	30,000	15.0%	1.0
	13	70,000	11.0%	0.6
HVAC	14	95,000	11.1%	3.2
	15	30,000	10.0%	4.6

Results: Financially Unconstrained Scenario

Under the conditions defined by the financially unconstrained scenario, total Industrial sector natural gas savings in 2017 are estimated to be approximately 846 million m^3/yr. This represents a saving of approximately 15%, relative to the Reference Case, and is equal to approximately 44% of the savings identified in the Economic Potential Forecast. Further detail is provided in the following exhibits:

- Exhibit 6.10 shows total natural gas savings by service region and milestone year
- Exhibit 6.11 shows total natural gas savings by sub sector and milestone year for the total Union Service Area
- Exhibit 6.12 shows total natural gas savings by end use and milestone year for the total Union Service Area
- Exhibit 6.13 shows total natural gas savings by sub sector and end use for 2017 for the total Union Service Area
- Exhibit 6.14 shows annual natural gas savings for the year 2017 by technology, together with the estimated program costs and TRC benefits for the total Union Service Area. (**Note**: the values shown in Exhibit 6.14 are for the single year 2017 only; consequently, they do not add to the same values shown in the preceding exhibits.)

[76] Fixed program costs and incentive levels were provided by Union based on workshop results and current experience. Where fixed program costs apply to a bundle of measures, costs are distributed among the measures weighted by total savings potential.

Exhibit 6.10: Natural Gas Savings by Service Region and Milestone Year, Financially Unconstrained Scenario (1000 m3/yr.)

Milestone Year	Southern Region	Northern Region	Total	% Savings Relative to Ref Case
	1000 m^3/yr.			
2012	394,898	162,208	557,106	10.2%
2017	583,749	262,425	846,175	15.1%
% Savings 2017 Re: Reference Case	15%	15%	15%	
% Savings 2017 Re: Total	69%	31%	100%	

Exhibit 6.11: Natural Gas Savings by Sub Sector and Milestone Year for the Total Union Service Area, Financially Unconstrained Scenario (1000 m3/yr.)

Sub-Sector	Milestone Year		% Savings 2017	
	2012	2017	Re: Ref Case	Re: Total
	1000 m^3/yr.			
Contract Primary Metal[77]	168,588	254,331	16.2%	30.1%
Contract Chemical	99,433	173,877	14.0%	20.5%
Other Chemical	3,445	5,603	14.0%	0.7%
Contract Paper	37,445	45,808	14.6%	5.4%
Contract Transportation and Machinery	32,041	40,531	14.3%	4.8%
Other Transportation and Machinery	12,166	15,310	14.3%	1.8%
Contract Petroleum Refineries	42,346	63,350	15.5%	7.5%
Contract Mining	30,342	45,752	14.6%	5.4%
Contract Food and Beverage	23,439	39,067	14.9%	4.6%
Other Food and Beverage	4,704	6,733	14.9%	0.8%
Contract Non-Metallic Mineral	37,957	55,028	18.6%	6.5%
Miscellaneous Industrial	65,201	100,785	14.1%	11.9%
Total	557,106	846,175	15.1%	100.0%

[77] As highlighted in Section 2.3, an assessment of data obtained at the completion of this study indicated that up to about 42% of the Base Year natural gas consumption in the Contract Primary Metal sub sector could be considered as feedstock. It was not feasible to include the data in the study at this late stage of the study. The implication is that the energy efficiency potential in the Contract Primary Metal sub sector might be overstated.

Exhibit 6.12: Natural Gas Savings by End Use and Milestone Year for the Total Union Service Area, Financially Unconstrained Scenario (1000 m^3/yr.)

End Use	Milestone Year 2012	Milestone Year 2017	% Savings 2017 Re: Ref Case	% Savings 2017 Re: Total
	1000 m^3/yr.			
Systems	132,034	177,973	3.2%	21.0%
Hot Water Systems	8,747	12,001	5.7%	1.4%
Boiler Steam Systems	93,324	178,706	12.6%	21.1%
Process Heat	235,829	347,413	13.8%	41.1%
Other Process	6,067	12,176	5.4%	1.4%
HVAC	81,105	117,906	9.6%	13.9%
Total	557,106	846,175	15.1%	100.0%

Exhibit 6.13: Annual Natural Gas Savings by Sub Sector and End Use for 2017 for the Total Union Service Area, Financially Unconstrained Scenario (1000 m3/yr.)

Sub Sector	End Use: Systems	Hot Water Systems	Boiler Steam Systems	Process Direct Heat	Other Process	HVAC	Total	
Contract Primary Metal	51,328	1,562	21,102	157,238	2,045	21,056	254,331	30.1%
Contract Chemical	38,821	1,306	61,082	46,845	5,229	20,593	173,877	20.5%
Other Chemical	1,251	42	1,968	1,510	168	664	5,603	0.7%
Contract Paper	9,774	329	23,979	6,943	360	4,422	45,808	5.4%
Contract Transportation and Machinery	8,943	364	9,586	10,881	668	10,089	40,531	4.8%
Other Transportation and Machinery	3,378	138	3,621	4,110	252	3,811	15,310	1.8%
Contract Petroleum Refineries	12,597	401	8,944	37,272	373	3,765	63,350	7.5%
Contract Mining	10,092	3,520	10,261	16,548	951	4,381	45,752	5.4%
Contract Food and Beverage	8,259	1,354	18,235	7,751	734	2,735	39,067	4.6%
Other Food and Beverage	1,423	233	3,143	1,336	126	471	6,733	0.8%
Contract Non-Metallic Mineral	9,494	331	4,632	36,830	508	3,233	55,028	6.5%
Miscellaneous Industrial	22,614	2,421	12,154	20,150	760	42,687	100,785	11.9%
Total	177,973	12,001	178,706	347,413	12,176	117,906	846,175	
%	21%	1%	21%	41%	1%	14%		

Exhibit 6.14: Annual Natural Gas Savings by Technology for One Year of Program Activity (2017) for the Total Union Service Area, Financially Unconstrained Scenario

End Use	Bundle	Aggressive Achievable Potential 2017		Program Costs 2017	Program Costs per Unit Savings and TRC	
		Natural Gas Savings (1000 m^3/yr.)	TRC Benefits ('000 $)	('000 $)	Per Natural Gas Savings ($/m^3)	Per TRC Benefits ($/$)
System wide	1	1,327	4,168	120	0.09	0.03
	2	433	1,173	65	0.15	0.06
Boiler	3	4,411	11,315	500	0.11	0.04
	4	5,009	12,294	79	0.02	0.01
	5	3,142	1,311	185	0.06	0.14
	6	603	2,044	259	0.43	0.13
	7	3,606	3,697	58	0.02	0.02
	8	261	330	41	0.16	0.13
	9	975	18,442	1,301	1.33	0.07
Process	10	8,433	42,504	736	0.09	0.02
	11	1,627	7,789	419	0.26	0.05
Other	12	1,112	3,837	99	0.09	0.03
	13	12	327	87	7.45	0.27
HVAC	14	3,956	16,434	1,966	0.50	0.12
	15	8,873	20,554	2,207	0.25	0.11
Weighted Average					0.19	0.06

6.6.2 Static Marketing Scenario

The Static Marketing scenario is based largely on the results of the Static Marketing scenario that was explored during the Achievable Potential workshop. Consequently, it incorporates consideration of both market constraints and DSM program budget limitations, which are “roughly” consistent with current Union levels.

This scenario, therefore, provides a ‘high level’ estimate of the level of natural gas savings that could be achieved by Union’s industrial customers over the nine-year period beginning in 2009 and ending in 2017, assuming present levels of program activity and a somewhat different mix of programs. It also provides Union’s industrial DSM program personnel with a view of the relative potential contribution of individual sub sectors, end uses, technologies and service regions.

Major Assumptions: Static Marketing Scenario

- All measures that pass the measure TRC screen are included
- No program financial limit is set, except that all measures must continue to pass the measure TRC screen
- Participation rates are constrained by the market barriers noted in the workshop
- Participation rates for measures discussed in the workshop are employed directly and are shown in Exhibit 6.15
- Participation rates for the remaining measures are extrapolated from the workshop results and/or consultant experience and are shown in Exhibit 6.14

- Fixed program costs (e.g., advertising, training workshops, contractor certification, etc.) and incentive costs are included for each measure. The levels selected for the scenario are summarized in Exhibit 6.16. In each case the values shown draw on the workshop results and recent Union DSM program experience.

Exhibit 6.15: Participation Rates for Static Marketing Scenario

Workshop Reference Number	Upgrade Technology/Measure	Participation Rates in 2017 (% of eligible)			Adoption Curve Shape	Notes
		Small	Medium	Large		
	Sub-metering	40-60%	7-11%	40%	C	Based on workshop ref. I2
	Integrated control system	26-86%	17-77%	30-90%	C	Based on workshop ref. I2
	Process heat recovery to preheat make-up water	10-15%	8%	16-17%	A	Based on workshop ref. I1
	Boiler combustion air preheat	0-3%	0-17%	21-71%	B	Based on workshop ref. I5
	Minimize deaerator vent losses	82%	62%	94%	B	Based on workshop ref. I4
	Blowdown heat recovery	30-34%	32-35%	39-42%	B	Based on workshop ref. I4
	Blowdown control	13-16%	11%	19%	A	Based on workshop ref. I1
	Boiler water treatment	63-69%	64-72%	77-82%	A	Based on workshop ref. I1
	High-efficiency burners	25-96%	17-87%	29-100%	C	Based on workshop ref. I2
	Advanced boiler controls	45-70%	46-70%	68-90%	C	Based on workshop ref. I2
I4	Economizer	71-86%	54%	80%	B	Based on workshop ref. I4
	Boiler right sizing and load management	40-60%	23%	45%	A	Based on consultant experience
I1	Steam trap survey and repair	60-75%	45-48%	70-75%	A	Based on workshop ref. I1
	Condensate return	40-58%	29%	44%	A	Based on workshop ref. I1
	Insulation	75-80%	54%	75%	A	Based on workshop ref. I1
	Boiler maintenance	72-82%	87%	98%	A	Based on workshop ref. I1
	Condensing boiler	15-28%	6-7%	10-15%	B	Based on workshop ref. I5
	Direct contact hot water heaters	15-20%	3-6%	0%	A	Based on workshop ref. I1
	Instantaneous steam generation	82-89%	54%	0%	C	Based on consultant experience
	Exhaust gas heat recovery	37-54%	35-41%	45-62%	A	Based on workshop ref. I1
I2	High-efficiency burners and burner controls	39-64%	30-52%	49-64%	C	Based on workshop ref. I2
	Insulation	75-85%	49%	85%	A	Based on workshop ref. I1
	Advanced heating and process controls	30-50%	26-36%	35-44%	C	Based on workshop ref. I2
	Air curtains	4-5%	4%	6%	C	Based on consultant experience
I3	High-efficiency ovens	49-60%	32-42%	56-70%	C	Based on workshop ref. I3
	High-efficiency dryers	49-60%	32-42%	56-70%	C	Based on workshop ref. I3
	High-efficiency kilns	0-44%	0-24%	0-50%	C	Based on workshop ref. I3
	High-efficiency furnaces	0-50%	0-32%	0-58%	C	Based on workshop ref. I3
I5	Process heat recovery	42-59%	29-33%	50-67%	A	Based on workshop ref. I5
	Pollution control measures	0-10%	0%	0-26%	C	Based on consultant experience
	Hydrogen atmospheres for steel batch coil annealing	0-59%	0-28%	0%	A	Based on workshop ref. I5
	Radiant heaters	37-49%	31%	42%	A	Based on workshop ref. I5
	Automated temperature control	53-60%	42%	53%	C	Based on workshop ref. I2
	Solar walls	0%	1%	1-3%	A	Based on consultant experience
	Warehouse loading dock seals	57-60%	47%	57%	A	Based on workshop ref. I1
	Air curtains	78-81%	67%	78%	A	Based on workshop ref. I1
	Air compressor heat recovery	19-25%	9-12%	22-26%	A	Based on workshop ref. I5
	Destratification fans	10-15%	4-5%	15%	C	Based on consultant experience
	Ventilation & heat recovery optimization	34-44%	46-47%	49%	B	Based on consultant experience

Exhibit 6.16: Summary of Program Cost Assumptions

End Use	Bundle	Fixed Program Costs ($/yr.)	Incentive Level (% of installed cost)	Payback After Incentive (yrs)
System wide	1	35,000	3.0%	0.6
	2	20,000	10.0%	0.1
Boiler	3	70,000	15.0%	1.8
	4	20,000	N/A-Fixed Incentive	0.04
	5	35,000	12.0%	0.8
	6	20,000	15.0%	3.8
	7	10,000	15.0%	0.6
	8	20,000	N/A-Fixed Incentive	0.3
	9	30,000	4.8%	0.3
Process	10	50,000	7.9%	0.7
	11	60,000	4.7%	0.8
Other	12	20,000	4.3%	1.2
	13	40,000	3.2%	0.6
HVAC	14	50,000	5.0%	3.4
	15	20,000	5.0%	4.8

Results: Static Marketing Scenario

Using the assumptions listed above the market penetration rates were determined for each measure by sub sector. The market penetration rates were used in the model to estimate the natural gas savings for the Static Marketing scenario. Under the conditions defined by the Static Marketing scenario, total Industrial sector natural gas savings in 2017 are estimated to be approximately 524 million m^3/yr. This represents a saving of approximately 9%, relative to the Reference Case, and is equal to approximately 27% of the savings identified in the Economic Potential Forecast. Further detail is provided in the following exhibits:

- Exhibit 6.17 shows total natural gas savings by service region and milestone year
- Exhibit 6.18 shows total natural gas savings by sub sector and milestone year for the total Union Service Area
- Exhibit 6.19 shows total natural gas savings by end use and milestone year for the total Union Service Area
- Exhibit 6.20 shows total natural gas savings by sub sector and end use for 2017 for the total Union Service Area
- Exhibit 6.21 shows annual natural gas savings for the year 2017 by technology, together with the estimated program costs and TRC benefits for the total Union Service Area. (**Note**: the values shown in Exhibit 6.21 are for the single year 2017 only; consequently, they do not add to the same values shown in the preceding exhibits.)

Exhibit 6.17: Natural Gas Savings by Service Region and Milestone Year, Static Marketing Scenario (1000 m^3/yr.)

Milestone Year	Southern Region	Northern Region	Total	% Savings Relative to Ref Case
	1000 m^3/year			
2012	218,983	98,593	317,576	5.8%
2017	357,258	167,079	524,337	9.4%
% Savings 2017 Re: Reference Case	9%	10%	9%	
% Savings 2017 Re: Total	68%	32%	100%	

Exhibit 6.18: Natural Gas Savings by Sub Sector and Milestone Year for the Total Union Service Area, Static Marketing Scenario (1000 m^3/yr.)

Sub-Sector	Milestone Year		% Savings 2017	
	2012	2017	Re: Ref Case	Re: Total
	1000 m^3/year			
Contract Primary Metal	91,880	162,563	10.3%	31.0%
Contract Chemical	56,226	103,098	8.3%	19.7%
Other Chemical	1,948	3,322	8.3%	0.6%
Contract Paper	29,611	35,029	11.2%	6.7%
Contract Transportation and Machinery	18,152	23,949	8.5%	4.6%
Other Transportation and Machinery	6,892	9,047	8.5%	1.7%
Contract Petroleum Refineries	23,292	40,165	9.8%	7.7%
Contract Mining	17,646	28,135	9.0%	5.4%
Contract Food and Beverage	12,414	21,857	8.4%	4.2%
Other Food and Beverage	2,491	3,767	8.4%	0.7%
Contract Non-Metallic Mineral	20,140	35,135	11.9%	6.7%
Miscellaneous Industrial	36,884	58,269	8.1%	11.1%
Total	317,576	524,337	9.4%	100.0%

Exhibit 6.19: Natural Gas Savings by End Use and Milestone Year for the Total Union Service Area, Static Marketing Scenario (1000 m^3/yr.)

End Use	Milestone Year		% Savings 2017	
	2012	2017	Re: Ref Case	Re: Total
	1000 m^3/year			
Systems	88,406	118,008	2.1%	22.5%
Hot Water Systems	4,428	6,489	3.1%	1.2%
Boiler Steam Systems	50,771	99,410	7.0%	19.0%
Process Heat	116,421	220,899	8.8%	42.1%
Other Process	3,416	7,108	3.2%	1.4%
HVAC	54,134	72,423	5.9%	13.8%
Total	317,576	524,337	9.4%	100.0%

Exhibit 6.20: Annual Natural Gas Savings by Sub Sector and End Use for 2017 for the Total Union Service Area, Static Marketing Scenario (1000 m^3/yr.)

Sub Sector		End Use						
	Systems	Hot Water Systems	Boiler Steam Systems	Process Direct Heat	Other Process	HVAC	Total	
Contract Primary Metal	34,448	914	11,652	102,974	1,335	11,241	162,563	31.0%
Contract Chemical	25,486	758	35,475	27,210	2,993	11,175	103,098	19.7%
Other Chemical	821	24	1,143	877	96	360	3,322	0.6%
Contract Paper	6,417	191	13,905	4,041	207	10,269	35,029	6.7%
Contract Transportation and Machinery	5,923	172	4,850	6,458	383	6,163	23,949	4.6%
Other Transportation and Machinery	2,237	65	1,832	2,440	145	2,328	9,047	1.7%
Contract Petroleum Refineries	8,205	242	5,380	24,162	217	1,960	40,165	7.7%
Contract Mining	6,747	2,042	6,014	10,434	581	2,318	28,135	5.4%
Contract Food and Beverage	5,470	634	8,787	5,105	396	1,465	21,857	4.2%
Other Food and Beverage	943	109	1,514	880	68	253	3,767	0.7%
Contract Non-Metallic Mineral	6,334	189	2,704	23,907	274	1,726	35,135	6.7%
Miscellaneous Industrial	14,977	1,148	6,153	12,412	414	23,165	58,269	11.1%
Total	118,008	6,489	99,410	220,899	7,108	72,423	524,337	
%	23%	1%	19%	42%	1%	14%		

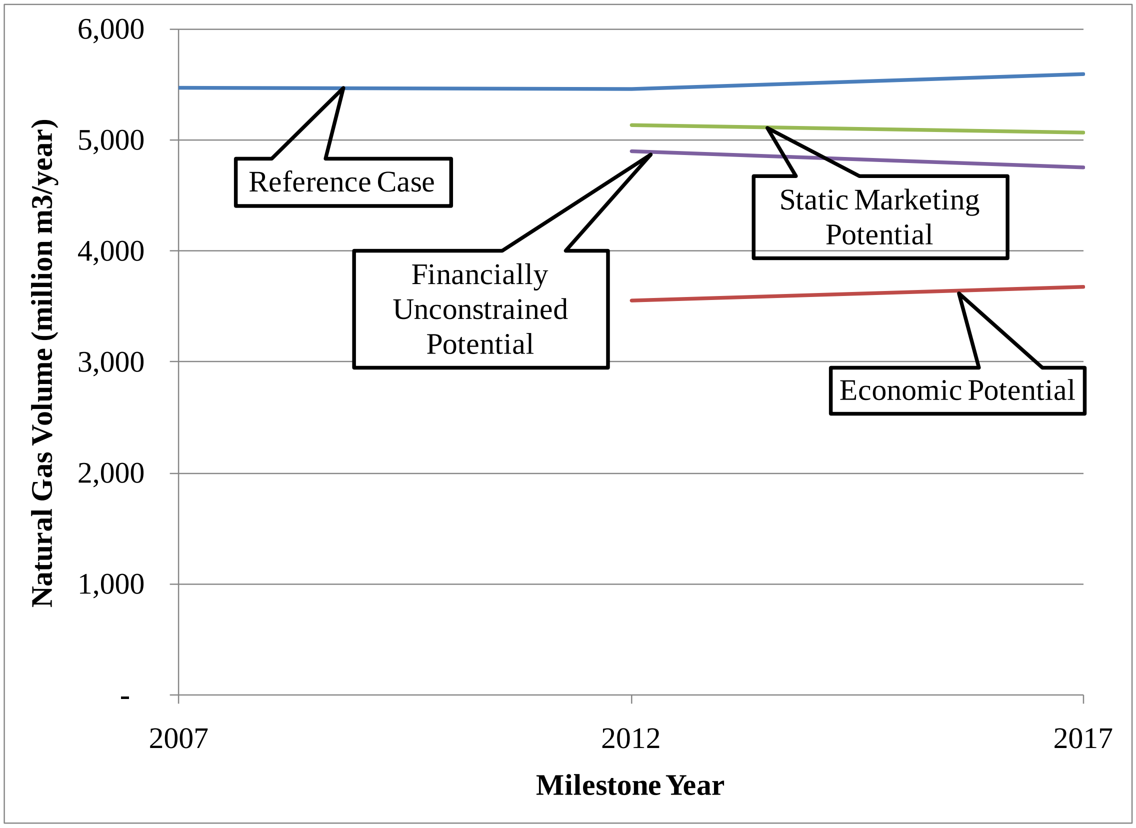
Exhibit 6.21: Annual Natural Gas Savings by Technology for One Year of Program Activity (2017) for the Total Union Service Area, Static Marketing Scenario

End Use	Bundle	Static Achievable Potential 2017		Program Costs 2017	Program Costs per Unit Savings and TRC	
		Natural Gas Savings (1000 m^3/yr.)	TRC Benefits ('000 $)	('000 $)	Per Natural Gas Savings ($/$m^3$)	Per TRC Benefits ($/$)
System wide	1	814	2,557	41	0.05	0.02
	2	355	961	23	0.06	0.02
Boiler	3	2,406	6,172	207	0.09	0.03
	4	2,270	5,572	26	0.01	0.005
	5	2,144	895	72	0.03	0.08
	6	255	864	68	0.27	0.08
	7	2,763	2,833	32	0.01	0.01
	8	110	140	22	0.20	0.16
	9	609	11,508	408	0.67	0.04
Process	10	4,516	22,760	189	0.04	0.01
	11	14,452	69,163	706	0.05	0.01
Other	12	657	2,270	32	0.05	0.01
	13	47	1,296	47	1.01	0.04
HVAC	14	2,214	9,196	534	0.24	0.06
	15	6,360	14,732	800	0.13	0.05
Weighted Average					0.08	0.02

6.7 SUMMARY AND INTERPRETATION OF RESULTS

Exhibit 6.22 provides a summary of the achievable natural gas savings under the Static Marketing and Financially Unconstrained scenarios presented in the preceding section. Results are shown relative to the Reference Case and Economic Potential Forecasts.

Exhibit 6.22: Achievable Potential versus Reference Case and Economic Potential Forecasts, for the Total Union Service Area



Further highlights are provided below.

The Financially Unconstrained Scenario

- Under the conditions defined by the Financially Unconstrained scenario, total Industrial sector natural gas savings in 2017 are estimated to be approximately 846 million m^3/yr. This represents a saving of approximately 15%, relative to the Reference Case and is equal to approximately 44% of the savings identified in the Economic Potential Forecast.

- The most significant opportunities for natural gas savings in this scenario are technologies that reduce gas usage for process heating, specifically ovens, dryers, kilns and furnaces. Implementation of energy-efficiency measures in boiler steam systems is also a significant opportunity. Implementation of measures to improve the total plant (referred to as system wide) energy efficiency is the third most significant opportunity area.

- Program costs per m^3 of natural gas savings in this scenario range widely by measure, from approximately $0.02 for bundles four and seven (both are bundles that apply to boiler steam systems), to $7.45 for bundle 13, which applies to process specific (referred to as "other") end use.

- Program costs per dollar of TRC benefit also show a wide range, from approximately $0.01 for bundle 4 to almost $ 0.27 for bundle 13.

- Weighted averages for the whole group of measures show 2017 program costs of approximately $0.19/$m^3$ of natural gas savings and approximately $0.06/TRC dollar. These values are approximately two to three times higher than Union's current program results.[78]

The Static Marketing Scenario

- Under the conditions defined by the Static Marketing scenario, total Industrial sector natural gas savings in 2017 are estimated to be approximately 524 million m^3/yr. This represents a saving of approximately 9%, relative to the Reference Case and is equal to approximately 27% of the savings identified in the Economic Potential Forecast.

- Similar to the Financially Unconstrained scenario, the most significant opportunities for natural gas savings are technologies and measures applicable to process heating, boiler steam systems and system wide (or plant wide).

- Program costs per m^3 of natural gas savings also range widely by measure in the Static Marketing scenario, from approximately $0.01 for bundles four and seven, to $1.01 for bundle 13.

- Program costs per dollar of TRC benefit show a similar wide range, from approximately $0.005 for bundle four to $0.16 for bundle eight.

- Weighted averages for the whole group of measures included in the Static Marketing scenario show 2017 program costs of approximately $0.08/$m^3$ of natural gas savings and approximately $0.02/TRC dollar. These values are relatively similar to Union's current program results.

[78] Union's audited results for its 2006 industrial DSM programs show that program spending of $3,500,000 achieved natural gas savings of 53,000,000 m^3 and TRC net benefits of $102,900,000. Expressed as a ratio, one dollar of program spending generated approximately 15.1 m^3 (approximately $0.07/$m^3$) of annual natural gas savings and just over $29 of TRC net benefits (approximately $0.03/TRC$).

7. CONCLUSIONS

This study has confirmed the existence of significant cost-effective DSM potential within all sub sectors of Union's Industrial sector. In fact, the levels of identified annual achievable potential savings are in the same order of magnitude as those captured in Union's 2007 program. However, the cost of achieving the identified savings is increasing.

Although the weighted average program cost values presented for both the Financially Unconstrained and Static Marketing scenarios will vary depending on the specific composition of the future program portfolio, both scenarios show an evident trend towards higher future costs to achieve natural gas savings and TRC benefits.[79] This trend recognizes that savings from DSM programs tend to become more expensive with time as the most attractive measures gain greater market penetration and only the more challenging measures remain.[80]

7.1 ADDITIONAL OBSERVATIONS

In addition to the preceding conclusions, three additional observations warrant note as they may affect future program strategies. They include:

- ***Rate of measure implementation has a large effect on overall savings:*** For measures that pass the TRC screen on an incremental cost basis, low participation rates in early milestone years create a significant "lost opportunity." This is particularly relevant to the replacement of equipment with a very long life, which is applicable to most industrial technologies and measures. The gap between Economic Potential and Achievable Potential savings presented in this study is due in large part to this significant lost opportunity that occurs in early milestone years.

- ***Bundling of measures to develop program concepts has an impact on the achievable potential and program development:*** To model the achievable potential scenario measures were grouped into bundles that are manageable within the scope and budget of the project. The results in Chapter 6 provide an indicative savings potential based on the specific set of bundles. Bundles with different combinations of measures will prioritize the measures in a different order from lowest to highest program cost per TRC benefit. In defining and developing specific programs it will be important to interpret the Achievable Potential by assessing individual measures within the context of the Economic Potential and the measure TRC results.

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79 Design of a DSM program portfolio is beyond the scope of this current study.

80 Over time, it is also expected that some relatively new technologies may become less expensive as they gain greater sales volumes.

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9. GLOSSARY

achievable potential
The Achievable Potential is the proportion of the natural gas savings identified in the Economic Potential Forecast that could realistically be achieved within the study period. Achievable Potential recognizes that it is difficult to induce customers to purchase and install all of the efficiency technologies that meet the criteria defined by the Economic Potential Forecast.

avoided cost
The unit cost of acquiring the next resource to meet demand, which is used as a measure for evaluating individual demand-side and supply-side options. In the context of this study "avoided cost" is the capital expenditure offset by Union Gas DSM activities (i.e., the cost of having to buy natural gas on the open market, contract for long-term supply, and/or build and run new storage/transmission facilities).

base year
The Base Year is the year to which all potentials will be compared. It provides a detailed description of "where" and "how" natural gas is currently used in each sector. For this study, it is the calendar year 2007. The modelled base year energy use is calibrated against Union's actual sales for 2007.

benefit/cost ratio
The measure benefit/cost ratio indicates the relative attractiveness of the measures. A measure that has a benefit/cost ratio in excess of 1.0 has benefits which outweigh its costs. Similarly, a measure with a benefit/cost ratio that is well in excess of one (e.g., 3.0) means that it is very attractive. A measure with a benefit/cost ratio of less than 1.0 has costs which outweigh its benefits.

building envelope
The material separation between the interior and the exterior environments of a building. The building envelope serves as the outer shell to protect the indoor environment as well as to facilitate its climate control.

co-generation
The simultaneous production of electric or mechanical energy and useful heat energy from a single fuel source.

combustion efficiency
The ratio of energy released during combustion to the potential chemical energy available in the fuel.

demand-side management (DSM)
Actions that modify customer demand for natural gas and that can defer the need for additional new supply.

discount rate
The interest rate used in calculating the present value of expected yearly benefits and costs.

economic efficiency
Allocation of human and natural resources in a way that results in the greatest net economic benefit, regardless of how benefits and costs are distributed within society.

economic potential forecast
The economic potential forecast is an estimate of the level of natural gas consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost effective from society's perspective. All of the energy-efficiency technologies and measures that have a positive measure TRC are incorporated into the economic potential forecast. These technologies and measures are applied at either natural stock turnover rates or at designated years for immediate application.

effective measure life (EML)
The estimate median number of years that the measures installed under a program are still in place and operable. EML incorporates field conditions, obsolescence, building remodelling, renovation, demolition and occupancy changes.

energy audit
An on-site inspection and cataloguing of energy using equipment/buildings, energy consumption and the related end-uses. The purpose is to provide information to the customer and the utility. Audits are useful for load research, for DSM program design and for identification of specific energy savings projects.

energy conservation
Activities by energy users that result in a reduction of the energy used to provide services. Energy conservation can include a wide variety of behavioural or operational changes that result in energy savings. For the purpose of this study, only energy savings achieved through physical or hardware installations are considered.

energy intensity
The ratio of energy consumed per application or end use. For example, gigajoules per square metre of heated office space per day, or gigajoules per tonne of aluminum produced. All else being equal, energy intensity increases as energy efficiency decreases.

emerging technologies
New energy-conserving technologies that are not yet market-ready, but may be market-ready over next 5 to 10 years. This category includes technologies that could be accelerated into the market during that period through targeted financial or technical support.

end use
The final application or final use to which energy is applied. End use is often used interchangeably with energy service.

energy savings
The savings that result from efficient technologies or activities. In this document, the term "energy" refers specifically to energy derived from natural gas unless otherwise noted.

energy service
An amenity or service supplied jointly by energy and other components/equipment such as buildings and heating equipment. Examples of energy services include residential space heating, commercial cooking, aluminum smelting and public transit. The same energy service can frequently be supplied with different mixes of equipment and energy.

energy use index (EUI)
End use energy consumption divided by a specific parameter of production (e.g., MJ/m^2., MJ/unit).

environmental credit/environmental penalty
An increment or decrement to the cost of a resource or set of resources, to reflect the overall level of its/their environmental impact, relative to another resource or set of resources.

financial incentive
Certain financial features in the utility's DSM programs designed to motivate customer participation. They may include features designed to reduce a customer's net cash outlay, pay-back period or cost of finance to participate.

fuel share
The proportion of requirements for a specific service met using a certain fuel. For example, a natural gas fuel share of 90% for space heating in commercial large office sub sector implies that 90% of the sub sector floor space is heated using natural gas. Similarly, a 90% natural gas fuel share in single family detached homes means that 90% of the space heating requirements for that dwelling type are met by natural gas.

gigajoule
One billion joules or one thousand megajoules.

interactive effects
In the context of natural gas use, interactive effects refer to the increase in gas consumed by heating equipment required to offset a decrease in "waste" heat generated by more efficient electrical fixtures or appliances after retrofit or replacement.

joule
The basic unit of energy. In physical terms, equal to the work required to move a mass of one Newton a distance of one metre.

kilowatt (kW)
One thousand watts; the most common unit of measurement of electric power. (The amount of energy transferred at a rate of one kilowatt for one hour is equal to one kilowatt hour.)

kilowatt hour (kWh)
The most common unit of measurement of electric energy. One kilowatt hour represents the power of one thousand watts for a period of one hour.

load forecast
An estimate of expected natural gas requirements that have to be met by the utility in future years.

load research
Research to disaggregate and analyze patterns of natural gas consumption by various sub sectors and end-uses. Load Research supports the development of the load forecast and the design of demand-side management programs.

measure total resource cost (TRC)
The Measure TRC is the net present value of energy savings that result from an investment in a energy efficiency measure. The Measure TRC is equal to its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy and equipment-specific operating & maintenance costs. This calculation includes among others, the following inputs: the avoided natural gas and electricity supply costs; the life of the measure; and the selected discount rate.

megajoule
One million joules.

natural conservation
The future change in energy intensity that is expected to occur in the absence of utility DSM programs.

non-participant test (NPT)
A test measuring what happens to rates due to changes in utility revenues and operating costs caused by a program. Rates will go down if the avoided cost is greater than the sum of the revenue lost plus the program costs. This test indicates the direction and magnitude of the expected change in rate levels.

operating and maintenance cost (O&M cost)
The cost refers to the operating and maintenance costs associated with running the specific equipment. It is also referred to as equipment-specific O&M cost.

rate
Generically refers to a utility's rate structure.

rate structure
The formulae used by a utility to calculate charges for the use of natural gas or electricity.

reference case forecast
An estimate of the expected level of natural gas consumption that would occur over the study period in the absence of any new utility DSM market interventions after 2008. It is the baseline against which the scenarios of energy savings are calculated. The Reference Case forecast incorporates an estimation of "natural conservation," namely, changes in end-use efficiency over the study period that are projected to occur in the absence of new market interventions by the utility.

saturation
The portion of floor area that receives a specific energy service. For example, a saturation of 86% for space cooling in the Large Office sub sector means that 86% of the sub sector floor space is cooled (regardless of fuel used to provide that cooling).

seasonal efficiency
The ratio of delivered useful energy relative to the input potential fuel energy determined over a full heating season (or year).

sector
A group of customers having a common type of economic activity. Union Gas divides its customers into three principal sectors: Residential, Commercial and Industrial. Sectors are further divided into sub sectors. For example, “Large Offices” is a sub sector of the Commercial sector.

service area
The portion of the Province of Ontario that receives service from Union Gas. Union Gas’ service area is spread across the Province of Ontario including northern, southwestern and southeastern cities and towns.

service region
For the purposes of this study, the total Union Gas service area is divided into two service regions. They are the Northern Region and Southern Region.

simple payback
The simple payback is generated to show the customer’s financial perspective. Simple payback is a measure of the length of time required for the cumulative savings from a project to recover its initial investment cost and other accrued costs, without taking into account the time value of money.

static marketing scenario
The Static Marketing scenario incorporates consideration of both market constraints and DSM program budget limitations, which are “roughly” consistent with current Union levels. It provides a ‘high level’ estimate of the level of natural gas savings that could be achieved by Union’s industrial customers over the nine-year period beginning in 2009 and ending in 2017, assuming present levels of program activity and a somewhat different mix of programs.

strategic conservation
Utility action to reduce the total natural gas demand. Strategic conservation is natural gas conservation induced by utility programs.

strategic load growth
Utility action to increase (annual) total natural gas demand for specific end uses.

sub sectors
A classification of customers within a sector by common features. Residential sub sectors are by type of home (SFD, duplex, apartment, etc.). Commercial sub sectors are generally by type of

commercial service (office, retail, warehouse, etc.). Industrial sub sectors are by product type (pulp and paper, solid wood products, chemicals, etc.).

supply curves
A curve illustrating the amount of energy available at an appropriate screened price in ascending order of cost.

Total Resource Cost (TRC) Test
A test that compares the total costs of energy efficiency investments, including natural gas conservation programs, to the social cost of natural gas. Un-priced environmental and social costs may be accounted for by changing the cost of either the investment under consideration or the total cost of natural gas in such a way that relative un-priced impacts are reflected. It is used in designing and evaluating programs that are developed from the Energy Efficiency Potential study's results.

utility cost
The total financial cost incurred by the utility to acquire energy resources. For DSM, the costs include all utility program costs, including incentive costs.

watt
The basic unit of measurement of power.

Natural Gas
Energy Efficiency Potential: Update 2008

Residential, Commercial and Industrial Sectors
Synthesis Report

Submitted to:

Enbridge Gas Distribution

Submitted by:

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Note: Report analysis substantially completed in December 2008.

List of Exhibits

1. INTRODUCTION

1.1 BACKGROUND AND OBJECTIVES

Enbridge Gas Distribution (Enbridge) is the largest natural gas utility in Canada with 1.9 million residential, commercial and industrial customers. Enbridge is a regulated utility with a Service Area in central and eastern Ontario that includes the cities of Toronto and Ottawa and the Niagara Region. Enbridge distributes approximately 13 billion m^3 of natural gas to its customers annually.

Since 1995, Enbridge has been delivering demand side management (DSM) programs to its customers following a decision of the provincial regulator, the Ontario Energy Board (OEB). Enbridge offers DSM programs to all customer rate classes and across all sectors.

Enbridge has been participating in a market of increasing DSM program maturity. This market is continually evolving in its engagement with energy efficiency through growing voluntary initiatives and more stringent codes and standards. In addition, changes in the economy have started to have negative impact on the commercial and industrial marketplace in Enbridge's Service Area.

In the DSM Generic Proceeding held in 2006, Enbridge committed to creating an updated Market Potential Study for input into the next DSM plan. When completed, the results of this Natural Gas Energy Efficiency Potential Study will provide a foundation that Enbridge can use to guide the development of its longer-term DSM strategy, including new programs. More specifically, this includes support for Enbridge's filing to the OEB regulatory application for the next multi-year DSM plan by:

- Estimating the achievable and economic potential for DSM measures across all applicable technologies, markets and sectors in Enbridge's Service Area
- Giving shape to, and refining ongoing energy-efficiency work by Enbridge in order to develop its next multi-year DSM plan, and
- Provide information that is actionable and can be easily converted to plan and program development.

1.2 STUDY SCOPE

This current study (Update 2008) is an update of the earlier Natural Gas Efficiency Potential Study that was completed for Enbridge in 2006. Consequently, to the extent possible, this study employs the same methodology, sector definitions, facility archetypes and geographical coverage as in the previous study. Additional details are provided below:

- **Sector Coverage:** The study addresses three sectors: Residential, Commercial[1] and Industrial.

[1] Throughout this report the term "Commercial" also includes institutional sectors, such as schools, hospitals, etc., unless otherwise noted.

- **Geographical Coverage**: The study results are presented for the total Enbridge Service Area and for two service regions: Central and Eastern. The study results are presented at the level of individual service region due to differences in building stock and weather conditions (heating degree days) that exist in the two regions.

  The Central service region is dominated by the Greater Toronto Area, but also includes customers in the Niagara region. Major municipalities in the Central service region include: Metropolitan Toronto (01), Mississauga (21), Richmond Hill (35), Whitby (45), and Niagara (76). The Eastern region is dominated by the City of Ottawa. Major municipalities in the Eastern service region include: Peterborough (47), Barrie (53), and Ottawa (65).

- **Study Period**: This study covers a 10-year period. The Base Year is the calendar year 2007, with milestone periods at five-year increments: 2012 and 2017. The Base Year of 2007 was selected, as this was the most recent calendar year for which complete customer data were available.

- **Technologies:** The study addresses the full range of natural gas energy efficiency measures together with selected renewable energy technologies that are currently commercially available, or are expected to be available within the first 5 years of this study period.

  The study also provides a high-level treatment of selected emerging technologies. Although it is not expected that these emerging technologies will significantly affect results in this study period, they provide insight into possible future directions that may influence the market for higher efficiency products.

1.2.1 Caveats

Readers are reminded of the following caveats when reviewing the results presented in this report:

- Energy Efficiency Potential studies, such as this one, provide a “big picture” assessment of the scope of energy efficiency opportunities within a specific service area. They are particularly valuable in identifying the level of aggregate savings, the key measures involved, their costs and the relative priority of individual sub markets and technologies. Because these studies must assess literally hundreds of combinations of technologies and sub markets, the assessment is necessarily high level. As such, these study results are intended to provide a foundation for detailed program design, but it must be emphasized that detailed program design requires substantial additional analysis.

- During the completion of this study, the world economy entered a period of unprecedented uncertainty that may have significant impact on the results of this study, particularly in the short term. For example, key factors underlying Enbridge’s load forecast and the study’s Reference Case such as gross domestic product (GDP), energy prices, new construction etc. may change. The net effect of these changes would be lower levels of future natural gas consumption. Similarly, the participation rates estimated during the Achievable Potential workshops do not explicitly take into account changes in consumer outlook as a result of the economic downturn. Although neither the extent nor the duration of the economic downturn is known at this time, the expected impact would be lower consumer spending and, hence, lower program participation rates than those presented in this report. The precise magnitude of the reduced program participation is unknown at this time.

- The analysis was conducted based on the current and expected future participation of other industry partners such as the federal government, led by Natural Resources Canada, the Ontario government, and the Ontario Power Authority (OPA). At the time of this writing, the future energy efficiency strategies and complementary programs to be pursued by these agencies is not certain. Over the duration of this forecast, impacts due to the changing roles of industry partners should be assessed from time to time and, in particular, should be included within Enbridge's following multi-year plan.

- The inclusion of natural conservation in the study's Reference Case does address some, but not necessarily all, free rider and spillover impacts. A more detailed assessment of free rider impacts is practical only as part of a detailed program design, which is beyond the scope of this study.

- As in any study of this type, the results presented in this report are based on a large number of important assumptions. Assumptions such as those related to the current and forecast costs of natural gas, the current penetration of energy efficient technologies, the rate of future economic growth and customer willingness to implement new energy efficiency measures are particularly influential. Wherever possible, the assumptions used in this study are consistent with those used by Enbridge and are based on best available information, which in many cases includes the professional judgement of the consultant team, client personnel and/or local experts. The reader should use the results presented in this report as best available estimates; major assumptions, information sources and caveats are noted throughout the report.

1.3 DEFINITIONS

This study employs numerous terms that are unique to analyses such as this one and consequently it is important to ensure that all readers have a clear understanding of what each term means when applied to this study. Below is a brief description of some of the most important terms.

Base Year Natural Gas Use The Base Year is the starting point for the analysis. It provides a detailed description of "where" and "how" natural gas is currently used in each sector. The bottom up profile of energy use patterns and market shares of energy using technologies was calibrated to actual Enbridge customer sales data.

Reference Case Forecast The Reference Case is a projection of natural gas consumption to 2017, in the absence of any new Enbridge DSM market interventions after 2008. It is the baseline against which the scenarios of energy savings are calculated. The Reference case forecast incorporates an estimation of "natural conservation", namely, changes in end use efficiency over the study period that are projected to occur in the absence of new market interventions by Enbridge.

Measure Total Resource Cost The Measure TRC calculates the net benefits that result from an investment in an efficiency technology or measure. The measure TRC is equal to its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy, water and equipment O&M costs. This calculation includes, among others, the following inputs: the avoided natural gas, electricity and water supply costs, the life of the technology, and the selected discount rate, which in this analysis has been set at 9.14%.

The Measure Total Resource Cost (TRC) test is the primary determinant of whether a measure is included in the economic potential.

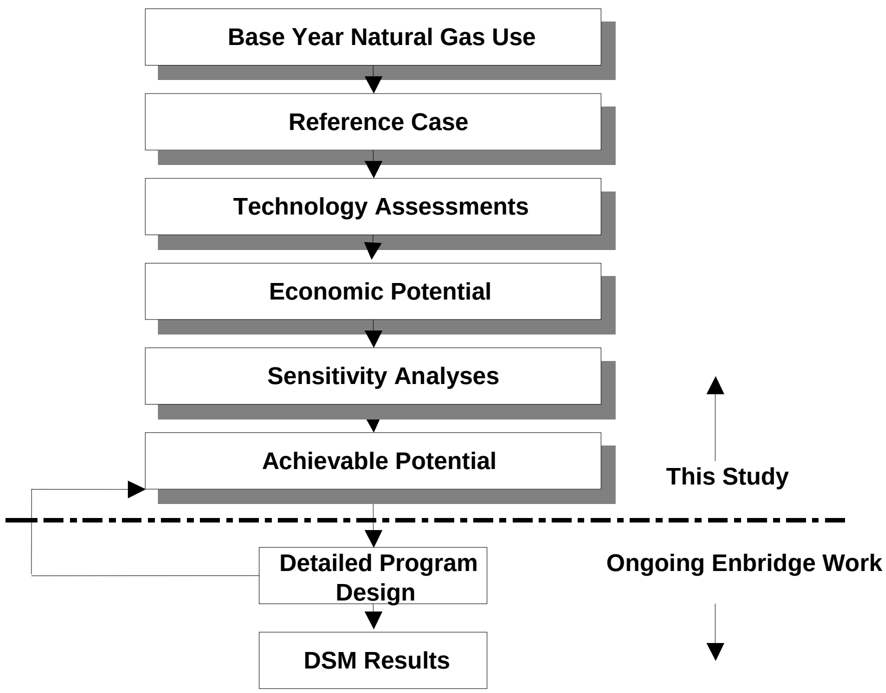
Economic Potential Forecast The Economic Potential Forecast is the level of natural consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost-effective from Enbridge's perspective. All the energy efficiency technologies and measures that have a positive measure TRC are incorporated into the Economic Potential Forecast. These technologies and measures are applied at either natural stock turnover rates or at designated years for immediate application.

Achievable Potential The Achievable Potential is the proportion of the natural gas savings identified in the Economic Potential Forecast that could realistically be achieved within the study period. Achievable Potential recognizes that it is practically difficult to induce customers to purchase and install all the efficiency technologies that meet the criteria defined by the Economic Potential Forecast.

1.4 APPROACH

To meet the objectives outlined above, the study was conducted through an iterative process that involved a number of well-defined steps. At the completion of each step, the client reviewed the results and, as applicable, revisions were identified and incorporated into the interim results. The study then progressed to the next step. A summary of the steps is presented in Exhibit 1.1 and briefly discussed below.

Exhibit 1.1: Major Study Steps



Step 1: Develop Base Year Calibration Using Actual Enbridge Sales Data

The Base Year (2007) is the starting point for the analysis. It provides a detailed description of "where" and "how" natural gas is currently used, based on actual natural gas sales.

The consultants compiled the best available data and used sector-specific macro models to estimate natural gas use; they then compared the results to the Enbridge's actual billing data to verify their accuracy.

Step 2: Develop Reference Case

The Reference Case uses the same sector-specific macro models to estimate the expected level of natural gas consumption that would occur over the study period with no new (post-2007) Enbridge DSM initiatives. The Reference Case includes projected increases in natural gas consumption based on expected rates of population and economic growth, using the growth rates included in the Enbridge 2007 load forecast. The Reference Case also makes an estimate for some "natural" conservation, that is, conservation that occurs without Enbridge DSM programs. The Reference Case provides the point of comparison for the calculation of Technical, Economic and Achievable natural gas saving potentials.

Step 3: Assess DSM Technologies

The consultants researched a wide range of commercially available DSM technologies and measures that can enable the Enbridge customers to use natural gas more efficiently. For each DSM technology or measure, the consultants calculated a value for the net benefits per year per cubic meter (m^3) of saved natural gas, referred to as the measure Total Resource Cost (TRC).

This approach allowed the consultants to compare the measure TRC benefits with other natural gas efficiency technologies and measures, and to determine whether or not to include the DSM measure in the Economic Potential Forecast. Only technologies and measures with positive TRC benefits were included in the Economic Potential Forecast.

Step 4: Estimate Economic Natural Gas Savings Potential

The Economic Potential Forecast incorporates all "cost-effective" DSM measures reviewed in Step 3. To forecast the potential natural gas savings that are defined as economic, the consultants used the sector-specific macro models to calculate the level of natural gas consumption that would occur if Enbridge's customers installed all "cost-effective" technologies. "Cost effective" for the purposes of this study means that the measure has a positive measure TRC.

Step 5: Conduct Sensitivity Analysis

The results presented in the Economic Potential Forecast are sensitive to the assumptions employed. Consequently, in consultation with Enbridge personnel, the Economic Potential results were subjected to a sensitivity analysis around two assumptions:

- **Technology Costs:** The Economic Potential Forecast was re-run using the most energy efficient technologies and measures assessed in Step 3, regardless of their current capital and installation costs (i.e., the most efficient technologies were included, even if they had a negative measure TRC value).[2] However, to ensure a measure of practical reality and basis for comparison with the preceding economic potential results, the technology adoption rates employed in this analysis are the same as those defined in the preceding economic potential forecast.

[2] In Enbridge's previous (2004) DSM Potential study, this analysis was reported as a separate Section entitled Technical Potential. The method and assumptions applied to current sensitivity analysis are the same as in the previous (2004) Technical Potential analysis.

- **Value of GHG Emissions**: The natural gas avoided cost values that were used to determine the measure TRC results presented in Step 4 do not include a value for greenhouse gas (GHG) emissions. However, the Government of Ontario has committed to aggressive GHG reduction targets. In this future context, it is not unreasonable to expect that future measure TRC calculations may incorporate a greenhouse gas (GHG) adder that accounts for carbon dioxide emissions resulting from natural gas consumption. Consequently, the measure TRC calculations were re-run using an avoided supply cost value that incorporates a GHG adder.

  The value of the GHG adder was set at \$15/tonne CO_2e (per tonne of CO_2 equivalent emissions) for the period 2007 to 2012 and \$20 /tonne CO_2e for the period 2013-2017. An emissions coefficient of 0.001903 tonnes CO_2e/m^3 (1903 g CO_2e/m^3) is used to account for carbon dioxide emissions resulting from natural gas consumption, while an emissions coefficient of 0.000220 tonnes CO_2e/kWh (220 g CO_2e/kWh) represents the average carbon dioxide emissions from electricity production in Ontario.[3, 4]

Step 6: Estimate Achievable Natural Gas Savings Potential

The Achievable Potential is the proportion of the savings identified in the Economic Potential Forecast that could realistically be achieved within the study period. The study assessed achievable natural gas savings potential from two perspectives:

- ***Potential Savings in Future Natural Gas Consumption:*** For this perspective, the study calculated the change in natural gas consumption levels that could occur in a given milestone year due to the aggregate impact of **all** measures implemented over the period from the Base Year (2007) to the Milestone Year (2012 or 2017). This perspective provides Enbridge Gas with an estimate of future natural gas consumption under different levels of DSM investment.

  This portion of the analysis calculated savings relative to the Reference Case (i.e., no new DSM), which is consistent with the approach used to estimate savings under the Economic Potential forecast and the sensitivity analyses described above in Steps 4 and 5.

- ***Potential DSM Program TRC Benefits***: For this perspective, the study calculated the potential natural gas savings in accordance with the provisions defined by the Ontario Energy Board (OEB) and employed by Enbridge when submitting its DSM plan to the OEB. This perspective emphasizes the estimation of net TRC benefits and the annual natural gas savings presented are due to those measures installed in (only) a given milestone year (i.e., 2012 or 2017).

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[3] Based on emission factors and Global Warming Potentials (GWPs) presented in Environment Canada, National Inventory Report (1990-2005): Greenhouse Gas Sources and Sinks in Canada", pgs. 23 and 583, April 2007.

[4] Based on Ontario emission factors presented in Environment Canada, National Inventory Report (1990-2005): Greenhouse Gas Sources and Sinks in Canada", pg. 521, April 2007.

Within each of the above perspectives, the analysis of Achievable Potential was assessed under four different Marketing scenarios:

- One Financially Unconstrained scenario
- Three Financially Constrained scenarios, each limited by a different annual program budget, which for this study were set at $20 million, $40 million and $60 million.

Data on the costs and savings for each measure were combined with participation rates identified in the achievable workshops to generate measure-by-measure estimates of potential savings. These results were then compiled into a table and ranked according to TRC benefits per program dollar from least cost to most costly. From this table it was then possible to identify the most cost effective portfolio of measures at the $20 million, $40 million, $60 million and Financially Unconstrained budget levels together with the annual natural gas savings and net TRC benefits associated with each program budget level.[5]

The potential savings in future natural gas consumption were then calculated by selecting only those measures contained in the above table that passed at each budget level and milestone year. That package of measures was then applied in each of the sector models and the results were compared with those in the Reference Case and Economic Potential forecasts.

Further information on each of the Marketing scenarios is provided in each of the sector specific sections of this report.

1.5 STUDY ORGANIZATION AND REPORTS

The study was organized and conducted by sector using a common methodology, as outlined above. Following this introductory section, the remainder of this Synthesis Report is organized as follows:

- Section 2 presents the combined natural gas savings for the three sectors.
- Section 3 presents a summary of the natural gas savings for the Residential sector.
- Section 4 presents a summary of the natural gas savings for the Commercial sector.
- Section 5 presents a summary of the natural gas savings for the Industrial sector.

[5] There are numerous possible approaches to the selection of program measures; this approach was selected for simplicity and clarity.

2. SUMMARY OF STUDY FINDINGS

The study findings confirm the existence of significant remaining cost-effective natural gas DSM opportunities in the Residential, Commercial and Industrial sectors within Enbridge's service area.

2.1 TOTAL NATURAL GAS SAVING POTENTIAL

As presented previously in Section 1, the study estimated natural gas savings potential from two perspectives.

- **Potential Savings in Future Natural Gas Consumption –** This perspective estimates the reductions in future natural gas consumption based on the aggregate impact of DSM measures implemented over the study's 10-year time period.
- **Potential DSM Program TRC Benefits –** This perspective estimates the total lifetime savings due to those measures installed in (only) a given milestone year (i.e., 2012 or 2017). This is the method employed in the calculation of net TRC benefits and is part of the DSM program portfolio design process.

The savings associated with each perspective are summarized below.

2.1.1 Potential Savings in Future Natural Gas Consumption

Exhibits 2.1 and 2.2 provide a summary of the total annual natural gas consumption levels contained in each of the forecasts addressed by the study.[6]

Exhibits 2.3 and 2.4 provide a summary of the potential natural gas savings under each of the potential scenarios; in each case savings are presented in both volumetric (m^3) and percentage terms. In each case the savings shown are annual and are based on the aggregate impact of measures installed in prior years within the period when compared to the Reference Case consumption levels.

As illustrated in Exhibits 2.1 to 2.4, inclusive, Achievable Potential savings increase only marginally beyond the $40M scenario. Based on the Achievable Potential workshop results, few additional savings were identified in the $60M scenario and Financially Unconstrained scenarios, while maintaining a positive TRC.

[6] Note: Actual results may not be linear as shown in Exhibits 2.1 and 2.2.

Exhibit 2.1: Graphic of Forecast Results for the Total Enbridge Service Area – Annual Natural Gas Consumption

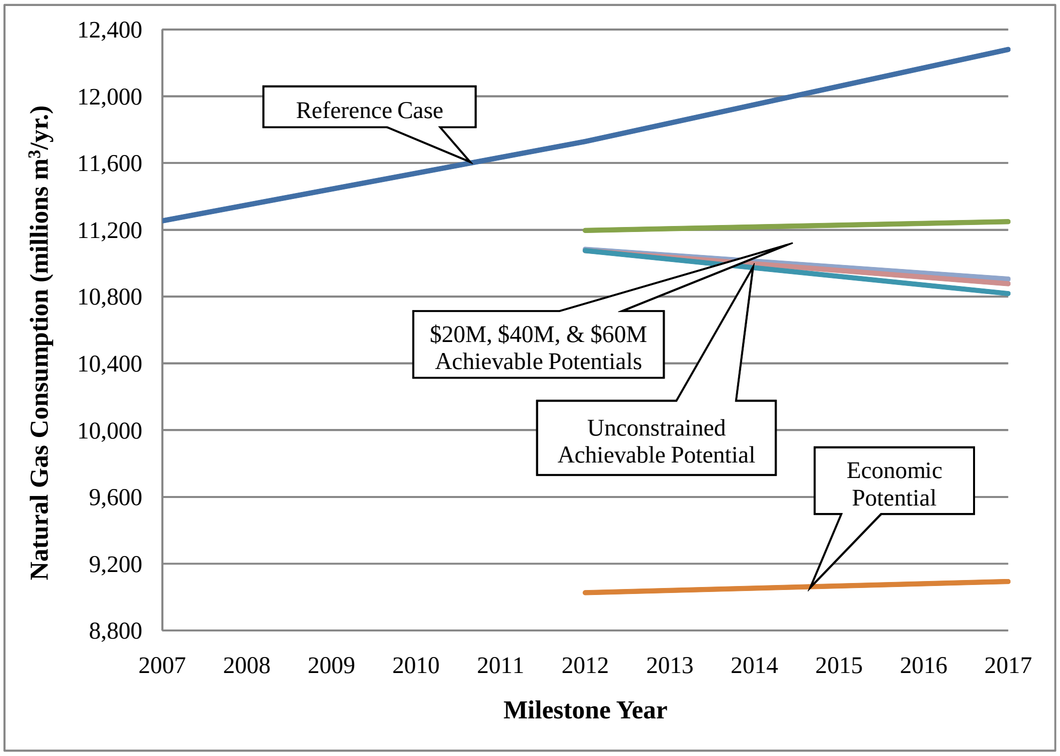


Exhibit 2.2: Total Annual Natural Gas Consumption, by Milestone Year and Forecast Scenario, 3 Sectors

Milestone Year	Total Annual Natural Gas Consumption, All Sectors (million m^3/yr.)					
	Reference Case	Economic Potential	Achievable Potential			
			$20M Scenario	$40M Scenario	$60M Scenario	Financially Unconstrained
2007	11,254					
2012	11,728	9,026	11,197	11,083	11,076	11,076
2017	12,280	9,093	11,249	10,905	10,877	10,818

Exhibit 2.3: Total Natural Gas Savings, in the Milestone Years and Forecast Scenario Relative to Reference Case and Economic Potential Forecasts, 3 Sectors

Milestone Year	Natural Gas Savings, All Sectors (million m^3/yr. vs. Ref Case, % vs. Ref. Case and Econ. Potential)				
	Economic Potential	Achievable Potential Scenarios			
		$20M Scenario	$40M Scenario	$60M Scenario	Financially Unconstrained
2012	2,703	532	645	652	652
2017	3,188	1,032	1,375	1,404	1,463
Savings as % of Reference Case Consumption					
2012	23%	5%	6%	6%	6%
2017	26%	8%	11%	11%	12%
Savings as % of Economic Potential Savings					
2012		20%	24%	24%	24%
2017		32%	43%	44%	46%

Note**:** Natural gas savings in the milestone years represent the potential reduction in gas use in that year as a result of DSM measures implemented in the period. Achievable Potential savings increase only marginally beyond the $40M scenario. Based on the Achievable Potential workshop results, few additional savings were identified in the $60M scenario and Financially Unconstrained scenarios, while maintaining a positive TRC.

Exhibit 2.4: Distribution of Natural Gas Savings, by Sector and Scenario in 2017, 3 Sectors

Sector	Natural Gas Savings, 2017 (million m^3/yr. vs. Ref Case, % of Econ. Potential Savings)				
	Economic Potential	Achievable Potential Scenarios			
		$20M Scenario	$40M Scenario	$60M Scenario	Financially Unconstrained
Residential	842	237	268	296	355
Commercial	1,427	440	715	715	715
Industrial	919	355	392	392	392
Total	3,188	1,032	1,375	1,404	1,463
Achievable Savings as % of Economic Potential Savings					
Residential		28%	32%	35%	42%
Commercial		31%	50%	50%	50%
Industrial		39%	43%	43%	43%
Total		32%	43%	44%	46%

Note**:** Natural gas savings in the milestone years represent the potential reduction in gas use in that year as a result of DSM measures implemented in the period. Achievable Potential savings increase only marginally beyond the $40M scenario. Based on the Achievable Potential workshop results, few additional savings were identified in the $60M scenario and Financially Unconstrained scenarios, while maintaining a positive TRC.

2.1.2 Potential DSM Program TRC Benefits

Exhibit 2.5 presents a summary of the forecast TRC benefits, annual program costs and natural gas savings in 2017 for each of the achievable scenarios, by scenario and sector. As noted previously, the natural gas savings shown in Exhibit 2.5 are calculated in accordance with OEB requirements for the filing of DSM plans. Therefore, the savings shown are only for the measures installed in 2017; they do not include the savings in 2017 that occur as a result of measures installed in prior years within the period.

Exhibit 2.5: Forecast Annual Achievable Program Costs[7], Savings[8] and TRC Benefits, by Scenario For Installations Completed in (only) 2017, 3 Sectors

Scenario	Forecast Achievable Program Costs and Savings, 2017				
	Annual Program Cost (millions $)	Gas Savings (million m^3/yr.)	TRC Benefits (million $)	Program Cost per Unit	
				($/$m^3$)	($/TRC$)
Residential (50% of Funding)					
$20M Annually	10.0	21.1	46.4	0.47	0.22
$40M Annually	20.0	27.0	47.2	0.74	0.42
$60M Annually	30.0	32.4	47.9	0.92	0.63
Financially Unconstrained	36.2	35.0	48.0	1.03	0.75
Commercial (30% of Funding)					
$20M Annually	6.0	48.9	168.1	0.12	0.04
$40M Annually	10.9	66.8	202.5	0.16	0.05
$60M Annually	10.9	66.8	202.5	*	*
Financially Unconstrained	10.9	66.8	202.5	*	*
Industrial (20% of Funding)					
$20M Annually	4.0	44.3	44.0	0.09	0.09
$40M Annually	4.4	48.0	44.3	0.09	0.10
$60M Annually	4.4	48.0	44.3	*	*
Financially Unconstrained	4.4	48.0	44.3	*	*
Total (3 Sectors)					
$20M Annually	20.0	114.3	258.5	0.18	0.08
$40M Annually	35.3	141.8	294.0	0.25	0.12
$60M Annually	45.3	147.3	294.7	**	**
Financially Unconstrained	51.5	149.8	294.8	**	**

** Based on the participation rates identified during the Achievable workshop results, all eligible measures are implemented at the program spending level shown.*
*** Values are not calculated as they are skewed by the Commercial and Industrial sector limits.*

2.2 OBSERVATIONS AND IMPLICATIONS

As illustrated in the preceding exhibits, despite a decade of successful DSM program implementation, there remains significant cost-effective DSM potential within Enbridge's service area. This remaining opportunity reflects, in part, continued technology cost and performance improvements over the period. Key study observations are highlighted below.

❑ Economic Potential

The study estimated economic potential savings to be approximately 3,188 million m^3 by 2017, which is approximately 26% relative to the Reference Case. This value is significantly larger than the value estimated in Enbridge's 2004 study; the change reflects a significant

[7] Program costs do not include salary and overhead costs.

[8] The savings shown in Exhibit 2.5 are only for the measures installed in 2017; they do not include the savings in 2017 that occur as a result of measures installed in prior years within the period.

increase in the Commercial sector savings opportunities, which is due to a combination of better information (that enabled better opportunity identification) and technology cost and performance improvements that widened the scope of technologies that passed the economic screen.

- **Achievable Potential Savings - Future Natural Gas Consumption**

Relative to the Reference Case forecast for 2017, the Achievable Potential savings range from about 1,375 million m^3 in the $20 million scenario to approximately 1,463 m^3 in the Financially Unconstrained scenario, which represent 43% and 46%, respectively, of the economic potential savings.

In the residential and commercial sectors, two related factors contribute to the gap between the economic and achievable potential results. First, many of the energy efficiency measures are applicable as existing equipment turns over or new facilities are constructed. This means that during the first few years when programs were deemed to be in the start-up phase, a significant number of lost opportunities occur. Secondly, the study period is relatively short; hence, both the amount of stock turn-over that occurs in the period and the number of years to achieve results is shortened.

- **Potential DSM Program TRC Benefits**

TRC benefits, annual program costs and natural gas savings identified in this study remain in the same orders of magnitude as Enbridge's recent experience, with a general trend towards increasing costs per unit of gas savings.

- Residential sector program costs identified in this study under the $20 million DSM scenario are $0.47/$m^3$ as shown in Exhibit 2.5. This compares with 2007 actual costs that were in the range of $0.32 (gross) to $0.51 per m^3 (net).[9] Residential program costs per unit of gas savings and TRC benefits are significantly greater than in either the Commercial or Industrial sectors. This is also consistent with recent Enbridge results.

- Commercial sector program costs identified in this study under the $20 million DSM scenario are $0.12/$m^3$ as shown in Exhibit 2.5. This compares with 2007 actual costs that were in the range of $0.14 (gross) to $0.11 per m^3 (net). Commercial sector program costs per dollar of TRC benefits are the lowest among the three sectors; however, the sector runs out of cost-effective measures before reaching the limits set within the $40 million or $60 million scenarios. This situation reflects the views of the achievable workshop participants who indicated that participation rates in this sector were limited by market barriers, such as supply chain capacity, split incentives etc., that were particularly challenging.

- Industrial sector program costs identified in this study under the $20 million DSM scenario are $0.09/$m^3$ as shown in Exhibit 2.5. This compares with 2007 actual costs that were in the range of $0.11 (gross) to $0.06 per m^3 (net). Industrial sector program costs are also much lower per unit of gas savings and TRC benefits than in the

[9] Enbridge, 2007 LRAM Post Audit Results.

Residential sector. However, as in the Commercial sector, the Industrial sector also runs out of cost-effective measures before reaching the limits set within the $40 million or $60 million scenarios.

- **Key Technologies and Measures**

In the Residential sector, the measures that provide the most significant contribution to annual savings differ somewhat by milestone year. Measures that offer particularly significant natural gas savings potential in both milestone years include air sealing in older homes, programmable thermostats, and high-performance windows. Measures such as ultra low-flow showerheads provide large savings in 2012 but not in 2017 as they are assumed to have fully penetrated the market by 2017.

In the Commercial sector, recommissioning represents the largest contribution to annual savings in both milestone years. Other measures that offer particularly significant natural gas savings potential in both milestone years include hot water conservation measures and efficient new construction.

In the Industrial sector, three measure bundles provide particularly attractive savings opportunities. They are: upgrading to more efficient boilers and heaters, such as condensing boilers and direct contact hot water heaters; retrofitting ovens, dryers, kilns and furnaces to improve efficiency, such as exhaust gas heat recovery, high efficiency burners, insulation and advanced heating and process controls; and, system wide integrated control systems.

- **Key Markets and Trends**

As the DSM market matures within Enbridge’s service area, niche or target markets are becoming increasingly important. Measures that may not pass the TRC test in a “typical” or “average” application often will pass in niche applications. For example:

- Air sealing and insulation in older homes (built before 1980) is one example that was included in this study, as data were available. Similarly, additional domestic hot water measures may be feasible in homes with a larger number of occupants. For example, drain water heat recovery systems and DHW recirculation systems become more economically attractive with larger household sizes. These latter measures have not been included in the current results as suitable data were not available.

Similarly, the sector specific results presented in the following sections indicate that market transformation approaches warrant additional consideration, particularly in the Residential and Commercial sectors. Alternately, opportunities such as those listed below suggest that the composition of the TRC calculation itself may need to be revisited to better consider non-energy benefits. For example:

- In the Residential sector, the technology cost sensitivity analysis showed that there remains an additional untapped potential savings by 2017 of about 1,100 million m^3 from technically mature measures that do not currently pass the TRC screen. The largest share of these additional potential savings is from air sealing and envelope insulation in existing homes. These measures do not pass the TRC screen as currently defined.

However, they provide non-energy benefits such as increased comfort and reduced noise that are not currently captured in the TRC calculation. In addition, industry specialists emphasized that as insulation levels increase, proper air and moisture sealing is becoming increasingly essential to the long-term structural integrity of Ontario's housing stock. This situation presents both an opportunity and a possible technical issue that may be better addressed through a market transformation approach.

- In the Commercial sector, the technology cost sensitivity analysis showed that there remains an additional untapped potential savings by 2017 of about 269 million m^3 from technically mature measures that do not currently pass the TRC screen. The largest share of these additional potential savings are from air sealing and envelope upgrades, including wall insulation and more energy efficient glazing measures in existing buildings. These measures do not pass the TRC screen as currently defined. However, as in the residential sector, the measures provide non-energy benefits such as increased comfort and reduced noise that are not currently captured in the TRC calculation.

In addition, industry specialists emphasized that some emerging technologies, such as solar preheated make-up air may be better addressed in a market transformation context, as they provide "soft" benefits, such as visible contribution to corporate greening goals, which are not included in the TRC calculation.

3. RESIDENTIAL SECTOR

The Residential sector includes single-family detached homes, attached duplex, row and multi-family dwellings and apartments as well as a small number of other dwellings.

3.1 APPROACH

The detailed end-use analysis of energy efficiency opportunities in the Residential sector employed two linked modelling platforms: **HOT2000,** a commercially-supported residential building energy-use simulation software, and **RSEEM** (Residential Sector Energy End-use Model), a Marbek in-house spreadsheet-based macro model.

The major steps in the general approach to the study are outlined in Section 1.4 above (Approach). Specific procedures for the Residential sector were as follows:

- **Modelling of Base Year –** The consultants used the Enbridge customer data to break down the Residential sector by four factors:

  - Type of dwelling (single detached, attached, apartment, etc.)
  - Heating category (natural gas or electric heat)
  - The age of the building
  - Service region.

  To estimate the natural gas used for space heating, the consultants factored in building characteristics such as insulation levels, floor space and air tightness using a variety of data sources, including the Ontario Energuide for Houses database, Enbridge billing data, local climate data and discussions with local contractors. They also used the results of Enbridge customer surveys that provided data on type of heating system, number and age of household appliances, renovation activity, etc. Based on the available data sources, the consultants calculated an average natural gas use by end use for each dwelling type. The consultant’s models produced a close match with actual Enbridge sales data.

- **Reference Case Calculations -** For the Residential sector, the consultants developed profiles of new buildings for each type of dwelling. They estimated the growth in building stock using the same data as that contained in the Enbridge most recent load forecast and estimated the amount of natural gas used by both the existing building stock and the projected new buildings and appliances. As with the Base Year calibration, the consultants’ projection closely matches Enbridge’s own 2007 forecast of future Natural gas requirements.

- **Assessment of DSM Measures –** To estimate the economic and achievable energy savings potentials, the consultants assessed a wide range of commercially available energy efficiency measures and technologies such as:
  - Thermal upgrades to the walls, roofs and windows of existing buildings
  - More efficient space heating equipment and controls
  - Measures to reduce hot water usage
  - Improved designs for new buildings
  - Addition of solar thermal technologies.

3.2 RESIDENTIAL NATURAL GAS SAVINGS POTENTIAL

A summary of the levels of annual natural gas consumption and potential natural gas savings contained in each of the Residential sector forecasts addressed by the study are presented in Exhibits 3.1 to 3.3, and are discussed briefly in the sub sections that follows.

Exhibit 3.1: Graphic of Forecast Results for the Total Enbridge Service Area – Annual Natural Gas Consumption, Residential Sector (million m³/yr.)

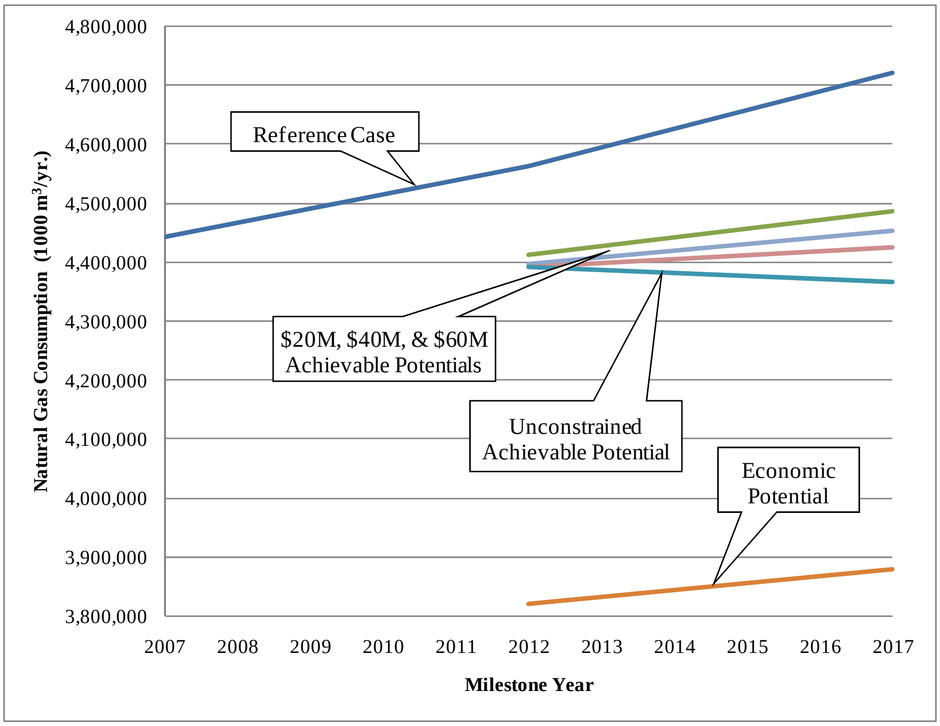


Exhibit 3.2: Summary of Forecast Results for the Total Enbridge Service Area – Annual Natural Gas Consumption, Residential Sector (million m³/yr.)

Milestone Year	Annual Consumption in Residential Sector (million m³/yr.)					
	Reference Case	Economic Potential	Achievable Potential			
			$20M Scenario	$40M Scenario	$60M Scenario	Financially Unconstrained
2007	4,442					
2012	4,563	3,820	4,413	4,399	4,392	4,392
2017	4,722	3,880	4,486	4,455	4,426	4,367

Exhibit 3.3: Summary of Forecast Results for the Total Enbridge Service Area – Natural Gas Savings in Milestone Years, Residential Sector (million m^3/yr. and % Relative to Economic Potential Scenario)

Milestone Year	Natural Gas Savings (million m^3/yr. Relative to Ref Case, % Relative to Economic Potential)				
	Economic Potential	Achievable Potential			
		$20M Scenario	$40M Scenario	$60M Scenario	Financially Unconstrained
2012	743	150	165	172	172
2017	842	237	268	296	355
2012		20%	22%	23%	23%
2017		28%	32%	35%	42%

Note**:** Natural gas savings in the milestone years represent the potential reduction in gas use in that year as a result of DSM measures implemented in the period.

3.3 BASE YEAR NATURAL GAS USE

In the Base Year of 2007, the Residential sector in Enbridge's total service area consumed about 4,442,437,000 m^3. Exhibit 3.4 shows that approximately 80% of the natural gas consumption in the residential sector occurs in the Single Family Detached dwellings, and of this amount, the pre-1980 vintage accounts for about 60%. The Duplex/Row/Multi category of housing accounts for approximately 11% of residential natural gas consumption, while Mobile/Other housing accounts for the remaining 9%.

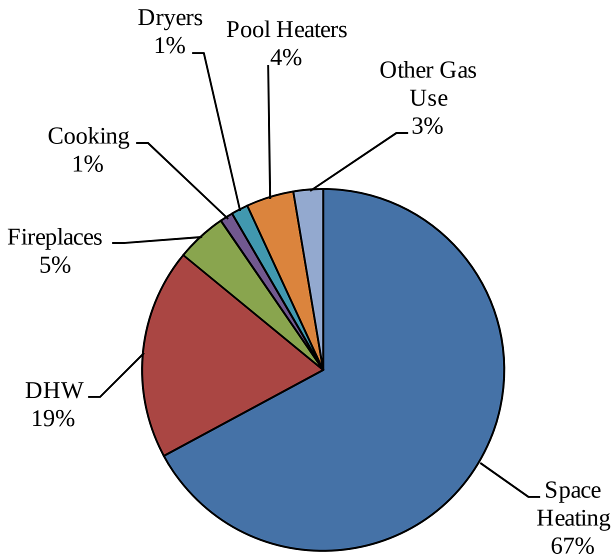
The Central Service region accounts for nearly 80% of the residential natural gas consumption in the Enbridge Gas Service Area.

Exhibit 3.4: Base Year Residential Sector Natural Gas Use for the Total Enbridge Service Area (1000 m^3/yr)

Segment	Space Heating	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use	Totals
	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.	1000 m^3/yr.
Detached - without gas space heat		16,301	6,310	998	1,326	4,602	2,274	31,812
Detached - pre-1980s	1,519,765	333,235	66,771	22,360	28,196	95,809	47,371	2,113,507
Detached - 1981 to 1993	387,972	133,595	37,598	7,401	10,165	52,379	18,177	647,287
Detached - 1993 to Present	431,296	155,765	64,147	10,478	13,958	35,210	21,556	732,409
Duplex/Row/Multi - no space htg		3,017	503	158	196		436	4,311
Duplex/Row/Multi - pre-1980s	243,499	53,418	4,672	2,996	3,553		7,711	315,849
Duplex/Row/Multi - 1980 or newer	160,787	64,827	10,058	3,383	4,249		9,068	252,372
Other	243,553	73,155	9,174	3,914	4,746		10,347	344,891
TOTAL	2,986,872	833,314	199,234	51,688	66,389	188,000	116,940	4,442,437

As illustrated in Exhibit 3.5 space heating accounts for about 67% of total residential natural gas use. Domestic hot water (DHW) accounts for about 19% of the total natural gas use, followed by fireplaces (5%) and pool heaters (4%). Dryers, cooking ranges and selected other uses, such as barbeques and patio heaters, account for the remaining natural gas consumption.

Exhibit 3.5: Base Year Residential Sector Natural Gas Use for the Total Enbridge Gas Service Area, by End Use



3.4 REFERENCE CASE

In the absence of new DSM initiatives, the study estimates that natural gas consumption in the Residential sector will grow from 4,442,437,000 m$^{3/}$yr in 2007 to about 4,772,205 m$^{3/}$yr in 2017. This represents an overall growth of about 7.4% in the period and compares very closely with Enbridge‘s own forecast, which also includes consideration of the impacts of “natural conservation.”

Exhibit 3.6 (overleaf) shows the forecast levels of Residential sector natural gas consumption for the entire Enbridge service area. The results are presented for each milestone year and end use.

Exhibit 3.6: Residential Sector Reference Case Natural Gas Use for the Total Enbridge Service Area, by Dwelling Type, End use and Milestone Year (1000 m^3/yr)

Dwelling Type	Milestone Year	Residential							
		Total	Space Heating	DHW	Fireplaces	Cooking	Dryers	Pool Heaters	Other Gas Use
Detached - without gas space heat	2007	31,812	0	16,301	6,310	998	1,326	4,602	2,274
	2012	32,174	0	16,571	5,728	1,065	1,413	4,951	2,446
	2017	32,625	0	16,777	5,348	1,126	1,493	5,275	2,606
Detached - pre-1980s	2007	2,113,507	1,519,765	333,235	66,771	22,360	28,196	95,809	47,371
	2012	2,007,253	1,440,802	316,074	57,232	22,180	27,785	95,809	47,371
	2017	1,936,122	1,394,135	299,192	50,078	22,002	27,535	95,809	47,371
Detached - 1981 to 1993	2007	647,287	387,972	133,595	37,598	7,401	10,165	52,379	18,177
	2012	615,655	367,814	126,715	32,227	7,341	11,002	52,379	18,177
	2017	592,787	355,900	119,947	28,198	7,282	10,903	52,379	18,177
Detached - 1993 to Present	2007	732,409	431,296	155,765	64,147	10,478	13,958	35,210	21,556
	2012	885,149	521,900	190,506	68,062	13,545	17,018	45,972	28,147
	2017	1,018,378	595,486	222,344	73,340	16,389	20,576	55,971	34,271
Duplex/Row/Multi - no space htg	2007	4,311	0	3,017	503	158	196	0	436
	2012	5,317	0	3,739	540	207	254	0	577
	2017	6,507	0	4,577	609	263	322	0	736
Duplex/Row/Multi - pre-1980s	2007	315,849	243,499	53,418	4,672	2,996	3,553	0	7,711
	2012	299,608	230,848	50,667	4,005	2,972	3,406	0	7,711
	2017	288,870	223,371	47,961	3,504	2,948	3,376	0	7,711
Duplex/Row/Multi - 1980 or newer	2007	252,372	160,787	64,827	10,058	3,383	4,249	0	9,068
	2012	370,211	234,735	96,261	12,628	5,344	6,758	0	14,486
	2017	494,219	308,157	132,258	16,077	7,563	9,558	0	20,606
Other	2007	344,891	243,553	73,155	9,174	3,914	4,746	0	10,347
	2012	347,865	244,816	74,359	8,327	4,181	5,051	0	11,131
	2017	352,699	248,030	75,272	7,774	4,428	5,336	0	11,858
TOTAL	2007	4,442,437	2,986,872	833,314	199,234	51,688	66,389	188,000	116,940
	2012	4,563,233	3,040,914	874,892	188,748	56,835	72,687	199,111	130,046
	2017	4,722,205	3,125,079	918,328	184,928	62,000	79,099	209,434	143,337

3.5 ASSESSMENT OF ENERGY EFFICIENCY MEASURES

The study assessed a total of approximately 50 potential energy efficiency measures. A summary of the screening results for the energy-efficiency measures is presented in Exhibit 3.7. Due to the number of measures assessed, Exhibit 3.7 shows only the results for those options that pass the screen in the Central service region.

Exhibit 3.7: Summary of Measure TRC Screening Results Residential Sector Energy-efficiency Options – Central Region

Measure	Measure Description	Full/Incr.	Simple Payback (Years)	Measure TRC ($)	Benefit/Cost Ratio
Ceiling Insulation	Attached (Existing)	Full	7.5	$17	1.04
High-Performance Windows (ENERGY STAR®)	Single Detached (Existing)	Incr.	6.0	$148	1.30
High-Performance Windows (ENERGY STAR®)	Attached (Existing)	Incr.	4.1	$304	1.87
High-Performance Windows (ENERGY STAR®)	Single Detached (New)	Incr.	3.6	$371	2.24
High-Performance Windows (ENERGY STAR®)	Attached (New)	Incr.	2.4	$445	3.23
Super High-Performance Windows	Single Detached (Existing)	Incr.	7.7	$22	1.02
Super High-Performance Windows	Attached (Existing)	Incr.	6.5	$141	1.20
Super High-Performance Windows	Single Detached (New)	Incr.	5.4	$281	1.47
Super High-Performance Windows	Attached (New)	Incr.	3.6	$460	2.15
Air Sealing and Insulation (Old Homes)	Single Detached (Existing)	Full	7.5	$58	1.03
Air Sealing and Insulation (Old Homes)	Attached (Existing)	Full	7.4	$67	1.04
Programmable Thermostats	Single Detached (Existing)	Full	0.5	$502	11.04
Programmable Thermostats	Attached (Existing)	Full	0.6	$442	9.84
Programmable Thermostats	Single Detached (New)	Incr.	0.7	$359	8.18
Programmable Thermostats	Attached (New)	Incr.	0.8	$313	7.27
Solar Orphans Program	Single Detached (Existing)	Full	3.9	$47	1.09
Solar Orphans Program	Attached (Existing)	Full	4.1	$29	1.06
High-Efficiency Fireplaces	Single Detached (Existing)	Incr.	2.4	$133	2.33
High-Efficiency Fireplaces	Attached (Existing)	Incr.	3.3	$65	1.65
High-Efficiency Fireplaces	Single Detached (New)	Incr.	3.5	$56	1.56
High-Efficiency Fireplaces	Attached (New)	Incr.	5.0	$10	1.10
Solar Preheated Make-Up Air	Single Detached (Existing)	Full	5.5	$214	1.16
Solar Preheated Make-Up Air	Attached (Existing)	Full	6.1	$66	1.05
Ultra Low-Flow Showerheads	Single Detached (Existing)	Full	0.2	$246	17.38
Ultra Low-Flow Showerheads	Attached (Existing)	Full	0.3	$215	15.31
Ultra Low-Flow Showerheads	Single Detached (New)	Full	0.3	$230	16.36
Ultra Low-Flow Showerheads	Attached (New)	Full	0.3	$200	14.32
Hot Water Pipe Insulation	Single Detached (Existing)	Full	0.1	$47	48.12
Hot Water Pipe Insulation	Attached (Existing)	Full	0.1	$46	46.52
DHW Temperature Reduction	Single Detached (Existing)	Full	0.0	$27	N/A
DHW Temperature Reduction	Attached (Existing)	Full	0.0	$26	N/A
Efficient Top Loading Clothes Washers	Single Detached (Existing)	Incr.	2.4	$315	2.26
Efficient Top Loading Clothes Washers	Attached (Existing)	Incr.	2.6	$259	2.03
Efficient Top Loading Clothes Washers	Single Detached (New)	Incr.	2.5	$289	2.16
Efficient Top Loading Clothes Washers	Attached (New)	Incr.	2.8	$234	1.94
Efficient Dishwashers	Single Detached (Existing)	Incr.	1.4	$125	3.50
Efficient Dishwashers	Attached (Existing)	Incr.	1.5	$114	3.29

Measure	Measure Description	Full/Incr.	Simple Payback (Years)	Measure TRC ($)	Benefit/Cost Ratio
Efficient Dishwashers	Single Detached (New)	Incr.	1.5	$111	3.22
Efficient Dishwashers	Attached (New)	Incr.	1.6	$101	3.01
Efficient Front Loading Clothes Washers	Single Detached (Existing)	Incr.	4.2	$141	1.28
Efficient Front Loading Clothes Washers	Attached (Existing)	Incr.	4.6	$79	1.16
Efficient Front Loading Clothes Washers	Single Detached (New)	Incr.	4.4	$111	1.22
Efficient Front Loading Clothes Washers	Attached (New)	Incr.	4.9	$51	1.10
Swimming Pool Covers	Single Detached (Existing)	Full	2.6	$833	1.69
Swimming Pool Covers	Single Detached (New)	Full	2.6	$833	1.69
Solar Pool Heaters	Single Detached (Existing)	Full	1.8	$4,824	3.61
Solar Pool Heaters	Single Detached (New)	Full	1.8	$4,824	3.61

3.6 ECONOMIC POTENTIAL FORECAST

Under the conditions of the Economic Potential Forecast,[10] the study estimated that natural gas consumption in the Residential sector would decline to about 3,880 million $m^{3/}$yr by 2017 for the total Enbridge service area. Annual savings relative to the Reference Case are about 842 million $m^{3/}$yr by 2017, or about 18%. Further details are provided in Exhibits 3.8 and 3.9, which show the results for both milestone years by dwelling type and end use, respectively.

Exhibit 3.8: Natural Gas Savings for the Total Enbridge Service Area by Dwelling Type and Milestone Year, Reference Case vs. Economic Potential (1000 m^3/yr.)

Dwelling Type	Milestone Year		% Savings 2017	
	2012	2017	Re: Ref Case	Re: Total
	1000 m^3/yr.			
Detached - without gas space heat	7,861	9,463	29%	1%
Detached - pre-1980s	401,529	417,743	22%	50%
Detached - 1981 to 1993	89,071	98,928	17%	12%
Detached - 1993 to Present	117,434	155,442	15%	18%
Duplex/Row/Multi - no space htg	989	1,521	23%	0%
Duplex/Row/Multi - pre-1980s	52,851	55,330	19%	7%
Duplex/Row/Multi - 1980 or newer	45,322	67,309	14%	8%
Other	28,303	36,159	10%	4%
Total	743,361	841,895	18%	100%

Note: Any difference in totals is due to rounding.

[10] The level of natural gas consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost-effective. In this study, “cost-effective” means that the technology upgrade passes the measure Total Resource Cost (TRC) test, as discussed previously in Section 1.4.

Exhibit 3.9: Natural Gas Savings for the Total Enbridge Service Area by End Use and Milestone Year, Reference Case vs. Economic Potential (1000 m^3/yr.)

End Use	**Milestone Year**		**% Savings 2017**	
	2012	**2017**	**Re: Ref Case**	**Re: Total**
	1000 m^3/yr.			
Space Heating	374,454	385,062	12%	46%
DHW	207,214	278,239	30%	33%
Fireplaces	5,413	9,805	5%	1%
Dryers	8,759	17,403	22%	2%
Pool Heaters	147,521	151,387	72%	18%
Total	743,361	841,895	18%	100%

Note: DHW savings include savings from reduced DHW consumption by efficient clothes washers and dishwashers. Any difference in totals is due to rounding.

3.6.1 Sensitivity Analysis

The Economic Potential results were subjected to a sensitivity analysis around two of the assumptions employed: Technology Cost and inclusion of a value for GHG emissions (as described in Step 5, in Section 1.4). The two sensitivity analyses offer the following insights:

- In the residential sector, there are a substantial number of measures that do not currently pass the economic screen but do offer substantial additional savings potential. Most of these measures provide improved thermal performance in existing dwellings.

  The Technology Cost sensitivity analysis identified potential savings of about 1,907 million m^3 in 2017; this compares with identified savings potential of about 734 million m^3 in 2017 under the Economic Potential forecast. Hence, the identified Technical savings potential is about a 2.6 times that identified in the Economic Potential forecast.

- The GHG adder makes a relatively small difference to the overall avoided cost of energy, and therefore, only a few additional measures pass the economic screen. Potential savings are increased by only a modest amount.

3.7 ACHIEVABLE POTENTIAL

As noted previously, Achievable Potential was assessed from two perspectives:

- Potential Savings in Future Natural Gas Consumption: Savings in one year due to the aggregate impact of measures implemented over the time period of Base Year (2007) to Milestone Year (2012 and 2017). This method calculates the net change in future natural gas supply requirements.

- Potential DSM Program TRC Benefits.[11] Savings due to (only) those measures implemented in one year. This method is used in calculation of the net TRC benefits.

Within each of the above perspectives, the analysis of Achievable Potential was assessed under four different Marketing scenarios:

- One Financially Unconstrained scenario
- Three Financially Constrained scenarios, each limited by a different level of program budget availability.

Further detail related to each of the Marketing scenarios is provided below followed by a summary of results.

3.7.1 Financially Unconstrained DSM Marketing Scenario

The Financially Unconstrained scenario provides an overview of the level of potential natural gas savings that could be achieved if a comprehensive portfolio of DSM programs was launched without any constraint on the availability of program funding, except for the requirement to maintain a positive TRC.

Although the results of this scenario are not constrained by program funding, the results do incorporate consideration of the market constraints identified during the Achievable Potential workshop, such as product and service availability and customer transaction costs.

This scenario, therefore, provides a high-level estimate of the upper level of natural gas savings that could be achieved by Enbridge's residential customers over the nine-year period beginning in 2009 and ending in 2017. It also provides Enbridge's residential DSM program personnel with a view of the relative potential contribution of individual sub sectors, end uses, technologies and service regions.

[11] The annual savings presented do not explicitly address the potential impact of free riders at the level of individual program measure. However, the Reference Case 3 does include an estimate of the impact of natural conservation over the study period, by end use (i.e., an estimate of natural gas savings that would occur in the absence of additional Enbridge DSM programs). Hence, the inclusion of natural conservation in the study's Reference Case does address some, but not necessarily all, free rider and spillover impacts. A more detailed assessment of free rider and spillover impacts is practical only as part of a detailed program design, which is beyond the scope of this study.

Major Assumptions: Financially Unconstrained Scenario

- All measures that pass the measure TRC screen are included
- No program financial limit is set, except that all measures must continue to pass the measure TRC screen
- Participation rates for each measure are based on the workshop results, which consider both market barriers and potential promotional strategies.

Exhibit 3.10 provides details on the program costs assumed for each measure.

Exhibit 3.10: Summary of Program Cost Assumptions, Financially Unconstrained Scenario[12]

Upgrade Technology/Measures	Fixed Program Costs ($/yr.)	Measure Basis	Measure Cost ($)[A]	Incentive Level (% of cost)	Payback After Incentive (yrs.)
High-Performance Windows	25,000	Incr.	500	100%	0.0
Super High-Performance Windows	25,000	Incr.	950	100%	0.0
Air Sealing and Insulation (Old Homes)	75,000	Full	2,000	45%	4.1
Attic/Ceiling Insulation		Full	600	45%	4.8
Programmable Thermostats	60,000	Full	50	36%	0.3
Solar Pre-Heated Make-Up Air	75,000	Full	1,300	75%	1.4
Ultra Low-Flow Showerheads	40,000	Full	15	100%	0.0
Efficient Dishwashers	30,000	Incr.	50	100%	0.0
Efficient Top Loading Clothes Washers		Incr.	250	40%	1.4
Efficient Front Loading Clothes Washers		Incr.	500	20%	3.3
DHW Temperature Reduction	50,000	Full	N/A	100%	0.0
Hot Water Pipe Insulation	1,000	Full	1	0%	0.1
High-Efficiency Fireplaces	50,000	Incr.	100	15%	2.0
Swimming Pool Covers	30,000	Full	1,200	5%	2.4
Solar Pool Heaters		Full	1,850	5%	1.7
Solar Orphans Program	20,000	Full	500	18%	3.2

[A] Where measure cost varies by region and/or housing type, the cost for existing single detached homes in the Central service region is shown

3.7.2 Financially Constrained DSM Marketing Scenarios

These DSM scenarios provide estimates of the potential impacts of increasingly larger annual DSM budgets that, as noted previously, were set at $20, $40 and $60 million annually. Within each of these budgets, 50% of the funding is allocated to the Residential sector for the purposes of this analysis; thus, the annual Residential sector budgets are $10, $20 and $30 million annually.

The Financially Constrained scenarios include the following DSM costs:

[12] Salary and related overhead costs are not included in program cost estimates. Also, the incentive levels are capped at 100% of the indicated measure cost.

- **Fixed Program Costs:** This includes costs for items such as newspaper advertisement, preparation of information and marketing materials, training workshops, contractor certifications, etc. These are program cost elements that would not be expected to vary significantly if the number of installations of the measure changed. Estimates for these cost items were provided by Enbridge personnel based on current and previous experience with similar DSM measures. In each case, these costs are expressed as dollars of program spending per year. Salary and related overhead costs are not included.

- **Incentive Costs:** These costs would include any costs that vary directly according to the number of installations of the measure. In each case, these costs are expressed as a percentage of the installed cost of the measure.

Exhibit 3.11 provides details on the program costs assumed for each measure.

Exhibit 3.11: Summary of Program Cost Assumptions, Financially Constrained Scenarios[13]

Upgrade Technology/Measures	Fixed Program Costs ($/yr.)	Measure Basis	Measure Cost ($)[A]	Incentive Level (% of cost)	Payback After Incentive (yrs.)
High-Performance Windows	25,000	Incr.	500	100%	0.0
Super High-Performance Windows	25,000	Incr.	950	100%	0.0
Air Sealing and Insulation (Old Homes)	75,000	Full	2,000	25%	5.6
Attic/Ceiling Insulation		Full	600	25%	6.5
Programmable Thermostats	60,000	Full	50	21%	0.4
Solar Pre-Heated Make-Up Air	75,000	Full	1,300	25%	4.1
Ultra Low-Flow Showerheads	40,000	Full	15	100%	0.0
Efficient Dishwashers	15,000	Incr.	50	100%	0.0
Efficient Top Loading Clothes Washers		Incr.	250	30%	1.6
Efficient Front Loading Clothes Washers		Incr.	500	15%	3.5
DHW Temperature Reduction	50,000	Full	N/A	100%	0.0
Hot Water Pipe Insulation	1,000	Full	1	0%	0.1
High-Efficiency Fireplaces	30,000	Incr.	100	10%	2.1
Swimming Pool Covers	10,000	Full	1,200	3%	2.5
Solar Pool Heaters		Full	1,850	3%	1.7
Solar Orphans Program	7,000	Full	500	18%	3.2

[A] Where measure cost varies by region and/or housing type, the cost for existing single detached homes in the Central service region is shown

[13] Salary and related overhead costs are not included in program cost estimates. Also, the incentive levels are capped at 100% of the indicated measure cost.

3.7.3 Achievable Potential Savings - Future Natural Gas Consumption[14]

Exhibits 3.12 to 3.14, inclusive, present a summary of the Achievable Potential savings in future natural gas consumption relative to the Reference Case levels. For illustration, the results of the Financially Unconstrained scenario are shown. Selected highlights are provided below.

- Exhibit 3.12 shows that total Residential sector natural gas savings in 2017 are estimated to be approximately 355 million m^3/yr. This represents a savings of approximately 8%, relative to the Reference Case and is equal to approximately 42% of the savings identified in the Economic Potential Forecast. The Central service region accounts for about 83% of the identified potential. In this scenario, the rate of introduction of full cost measures is limited by market constraints; as a result the potential savings in 2012 were estimated to be approximately 172 million m^3/yr., or about 23% of the savings identified in the Economic Potential Forecast, where full cost measures are introduced immediately.

- Exhibit 3.13 shows the results by dwelling type. As illustrated, single-family detached dwellings account for nearly 80% of the identified potential and over 60% of these potential savings are in dwellings built prior to 1980.

- Exhibit 3.14 shows the results by end use. As illustrated, measures that reduce space heating and domestic hot water loads account for approximately 87% of the identified potential, followed by pool heaters (10%), fireplaces (1%) and clothes dryers (1%). Additional detail on the specific measures that contribute to these end-use savings is provided in the following sections.

Exhibit 3.12: Natural Gas Savings by Service Region and Milestone Year, Financially Unconstrained Scenario (1000 m^3/yr.)

Milestone Year	Central Region	Eastern Region	Total	% Savings Relative to Ref Case
	1000 m^3/yr.			
2012	139,540	32,190	171,730	4%
2017	295,727	59,429	355,156	8%
% Savings 2017 Re: Reference Case	8%	6%	8%	
% Savings 2017 Re: Total	83%	17%	100%	

Note: Any difference in totals is due to rounding.

[14] See definition of savings as provided in Step 6, page 7.

Exhibit 3.13: Natural Gas Savings by Dwelling Type and Milestone Year for the Total Enbridge Service Area, Financially Unconstrained Scenario (1000 m^3/yr.)

Dwelling Type	Milestone Year 2012	Milestone Year 2017	% Savings 2017 Re: Ref Case	% Savings 2017 Re: Total
	1000 m^3/yr.			
Detached - without gas space heat	1,953	3,377	10%	1%
Detached - pre-1980s	75,646	168,649	9%	47%
Detached - 1981 to 1993	21,456	38,739	7%	11%
Detached - 1993 to Present	34,633	67,577	7%	19%
Duplex/Row/Multi - no space htg	392	735	11%	0%
Duplex/Row/Multi - pre-1980s	10,222	22,395	8%	6%
Duplex/Row/Multi - 1980 or newer	16,649	34,500	7%	10%
Other	10,779	19,184	5%	5%
Total	171,730	355,156	8%	100%

Exhibit 3.14: Natural Gas Savings by End Use and Milestone Year for the Total Enbridge Service Area, Financially Unconstrained Scenario (1000 m^3/yr.)

End Use	Milestone Year 2012	Milestone Year 2017	% Savings 2017 Re: Ref Case	% Savings 2017 Re: Total
	1000 m^3/yr.			
Space Heating	72,598	182,794	6%	51%
DHW	78,910	128,798	14%	36%
Fireplaces	1,497	3,931	2%	1%
Dryers	876	2,605	3%	1%
Pool Heaters	17,849	37,028	18%	10%
Total	171,730	355,156	8%	100%

Note: DHW savings include savings from reduced DHW consumption by efficient clothes washers and dishwashers. Any difference in totals is due to rounding.

3.7.4 Potential DSM Program TRC Benefits

Exhibits 3:15, 3.16 and 3.17 present the results for the milestone year 2017. As illustrated, annual Residential sector program spending of approximately $10 million in 2017 would result in the installation of measures providing approximately 21 million m^3/year in natural gas savings[15] and approximately $46 million in TRC net benefits. The exhibits also illustrate that even under the conditions defined by the Financially Unconstrained scenario, the Residential sector runs out of eligible cost-effective measures. Additional details are provided in the following exhibits.

- Exhibit 3.15 presents the 2017 results by upgrade technology or measure, including both the Current Marketing Level of customer participation and the increment from the Current Marketing Level to the Financially Unconstrained Marketing scenario. For each measure, annual natural gas savings potential, net TRC benefits and annual program costs are presented both individually and cumulatively. The measures are sorted in order of increasing program cost per dollar of TRC benefits. The 10

15 Note: the savings shown are only for the measures installed in 2017; they do not include the savings in 2017 that occur as a result of measures installed in prior periods.

measures contributing the most TRC benefits are assigned letters, matching the labels on Exhibits 3.14 and 3.15.

- Exhibit 3.16 presents the 2017 results graphically, with program costs on the vertical axis and net TRC benefits on the horizontal axis. All of the measures that pass the measure TRC screen are included here but balloons are added to indicate the location of the top ten measures (in terms of TRC benefits) on the curve. Three annual budget levels for residential program spending are shown as horizontal lines, for reference.

- Exhibit 3.17 presents the 2017 results graphically, with program costs on the vertical axis and annual natural gas savings potential on the horizontal axis. As with Exhibit 3.16, all of the measures which are included in the Achievable Potential analysis are shown here and balloons are added to indicate the positions of substantial measures on the curve. Sorting of the measures is based on program costs per unit TRC benefit.

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Exhibit 3.15: Summary of 2017 Achievable Results** by Measure, for the Total Enbridge Service Area

Reference (Marked on Graphs)	Upgrade Technology/Measures	Scenario	Annual Natural Gas Savings Potential (1000 m^3/yr.)		Net TRC Benefits ($)		Annual Program Costs ($)		Program Costs per Unit	
				Cumulative		Cumulative		Cumulative	per Natural Gas Savings ($/$m^3$)	per TRC Benefits ($/$)
	DHW Temperature Reduction	F. Unconstrained	7	7	$ 11,550	$ 11,550	$ -	$ -	N/A	N/A
A	Hot Water Pipe Insulation	F. Unconstrained	217	224	$ 560,411	$ 571,961	$ -	$ -	N/A	N/A
B	Hot Water Pipe Insulation	CML	1055	1,278	$ 2,718,359	$ 3,290,319	$ 1,000	$ 1,000	0.00	0.00
C	Solar Pool Heaters	CML	1877	3,156	$ 4,345,334	$ 7,635,653	$ 67,109	$ 68,109	0.04	0.02
D	Programmable Thermostats	CML	6902	10,058	$ 18,841,740	$ 26,477,393	$ 488,114	$ 556,223	0.07	0.03
E	Solar Pool Heaters	F. Unconstrained	3349	13,407	$ 8,068,567	$ 34,545,960	$ 213,392	$ 769,615	0.06	0.03
	Swimming Pool Covers	CML	49	13,457	$ 46,707	$ 34,592,667	$ 2,327	$ 771,942	0.05	0.05
	Swimming Pool Covers	F. Unconstrained	46	13,503	$ 47,735	$ 34,640,402	$ 4,728	$ 776,670	0.10	0.10
F	Programmable Thermostats	F. Unconstrained	1330	14,832	$ 3,650,170	$ 38,290,572	$ 417,087	$ 1,193,757	0.31	0.11
G	Efficient Top-Loading Clothes Washers	CML	1479	16,311	$ 3,272,110	$ 41,562,682	$ 532,910	$ 1,726,667	0.36	0.16
	High-Efficiency Fireplaces	CML	295	16,606	$ 353,129	$ 41,915,811	$ 74,426	$ 1,801,093	0.25	0.21
H	Efficient Dishwashers	CML	516	17,122	$ 1,088,993	$ 43,004,804	$ 377,905	$ 2,178,998	0.73	0.35
	Efficient Front-Loading Clothes Washers	CML	20	17,141	$ 14,943	$ 43,019,748	$ 6,234	$ 2,185,231	0.32	0.42
	High-Efficiency Fireplaces	F. Unconstrained	99	17,240	$ 111,782	$ 43,131,530	$ 63,842	$ 2,249,073	0.65	0.57
I	High-Performance Windows	CML	1636	18,876	$ 2,710,391	$ 45,841,921	$ 3,857,171	$ 6,106,244	2.36	1.42
	Solar Pre-Heated Make-Up Air	CML	678	19,553	$ 213,677	$ 46,055,598	$ 570,731	$ 6,676,975	0.84	2.67
	DHW Temperature Reduction	CML	36	19,589	$ 13,228	$ 46,068,826	$ 50,000	$ 6,726,975	1.39	3.78
	Ceiling Insulation	CML	19	19,608	$ 2,396	$ 46,071,222	$ 18,349	$ 6,745,324	0.98	7.66
	Solar Pre-Heated Make-Up Air	F. Unconstrained	627	20,235	$ 266,655	$ 46,337,878	$ 2,367,268	$ 9,112,592	3.78	8.88
	Air Sealing and Insulation (Old Homes)	CML	1891	22,126	$ 173,806	$ 46,511,683	$ 1,875,989	$ 10,988,581	0.99	10.79
	Ceiling Insulation	F. Unconstrained	112	22,238	$ 18,751	$ 46,530,434	$ 204,098	$ 11,192,679	1.82	10.88
J	Air Sealing and Insulation (Old Homes)	F. Unconstrained	11328	33,566	$ 1,485,712	$ 48,016,146	$ 20,863,983	$ 32,056,662	1.84	14.04
	Solar Orphans Program	F. Unconstrained	81	33,646	$ 1,135	$ 48,017,281	$ 42,377	$ 32,099,039	0.53	37.33
	Solar Orphans Program	CML	50	33,697	$ 530	$ 48,017,812	$ 25,457	$ 32,124,496	0.51	47.99
	Super High-Performance Windows	CML	425	34,121	$ -	$ 48,017,812	$ 1,298,272	$ 33,422,768	3.06	N/A
	Super High-Performance Windows	F. Unconstrained	902	35,024	$ -	$ 48,017,812	$ 2,763,279	$ 36,186,046	3.06	N/A
						Weighted Average (@ $10M Spending)			0.47	0.22
						Weighted Average (@ $20M Spending)			0.74	0.42
						Weighted Average (Total)			1.03	0.75

** Savings shown are incremental to those for preceding measures.

Exhibit 3.16: Achievable Potential Supply Curve, 2017: Program Cost vs. TRC Net Benefits, for the Total Enbridge Service Area

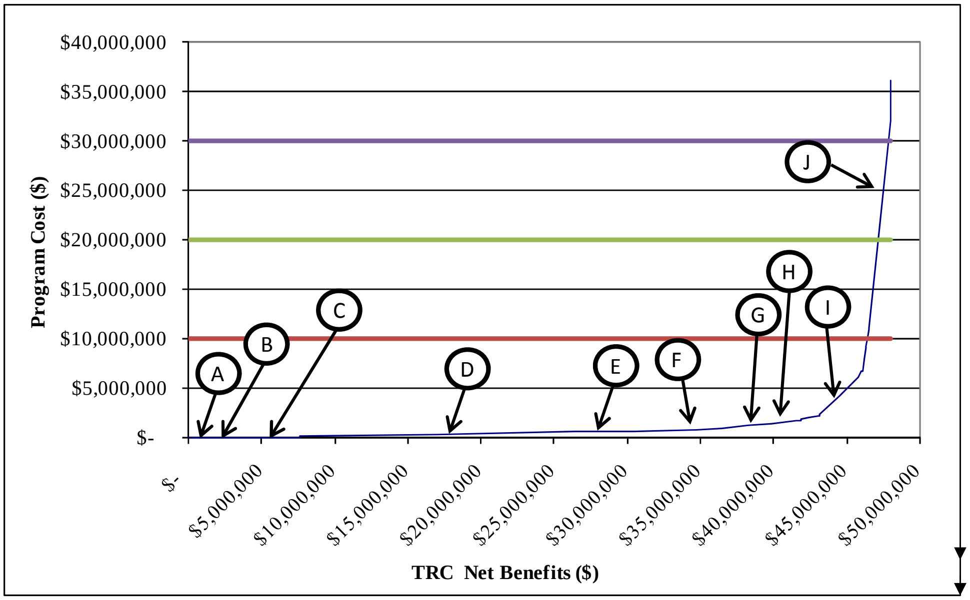
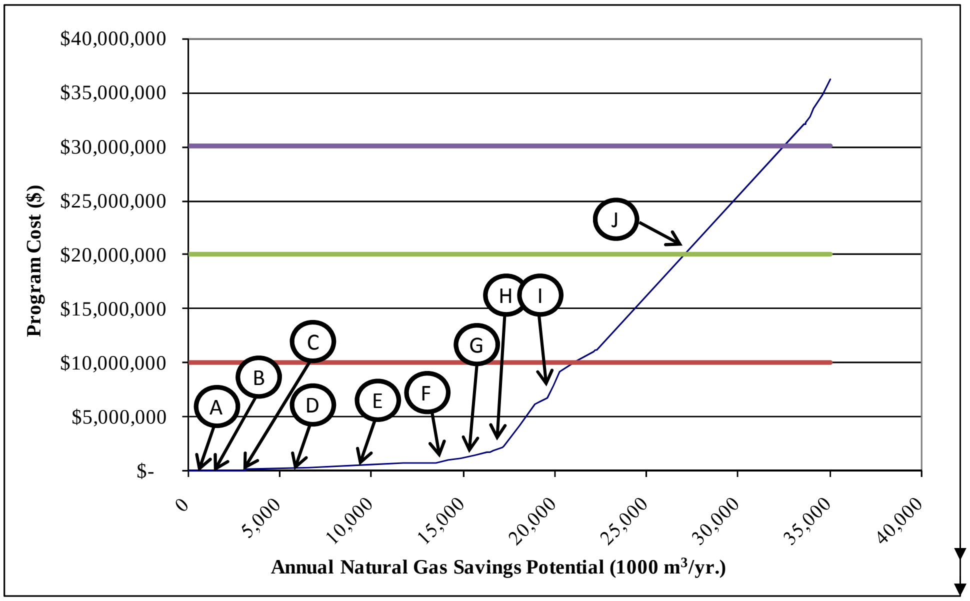


Exhibit 3.17: Achievable Potential Supply Curve, 2017: Program Cost vs. Annual Gross Natural Gas Savings Potential, for the Total Enbridge Service Area



3.7.5 Conclusions

Selected highlights are provided below.

- Program costs per dollar of TRC net benefits increase over the study period to 2017. This is because the measures with low installed cost are assumed to follow a more rapid adoption curve (Curve C, as described in the workshop), leaving more expensive measures to dominate the mixture in later years of the program.

- The supply curves show a sharp increase in program costs associated with capturing additional savings past an annual program spending of level of approximately $10 million on residential DSM.

- With residential program spending of approximately $10M in 2017, program costs are approximately $0.47 per gross m^3 of natural gas savings and $0.22 per dollar of gross TRC benefits. If residential program spending increases to $20M in the same year, program costs increase substantially to approximately $0.74 per gross m^3 of natural gas savings and $0.42 per dollar of gross TRC benefits. This compares with recent Enbridge monitoring and evaluation results[16] of $0.32 m^3 of gross natural gas savings ($0.51 per m^3 of net savings).

- The measures that provide the most significant contribution to annual savings differ somewhat by milestone year. Measures that offer particularly significant natural gas savings potential in both milestone years include air sealing in older homes, programmable thermostats, and high-performance windows. Measures such as ultra low-flow showerheads provide large savings in 2012 but not in 2017 as they are assumed to have fully penetrated the market by 2017.

- Although the weighted average program costs associated with each of the financially constrained scenarios will vary depending on the specific composition of future program portfolios[17], there is an evident trend towards higher future program costs to achieve natural gas savings and TRC benefits. This trend recognizes that savings from DSM programs tend to become more expensive with time as the most attractive measures gain greater market penetration and new performance standards are introduced, which leaves the more challenging measures.

[16] Enbridge, 2007 LRAM Post Audit Results.

[17] Design of a DSM program portfolio is beyond the scope of this current study.

3.8 ADDITIONAL OBSERVATIONS

Two additional observations warrant note as they may affect future residential program strategies. They include:

- ***Niche Markets Warrant Greater Program Focus:*** As the DSM market matures within Enbridge's service area, niche or target markets are becoming increasingly important. For example, measures that may not pass the TRC test in a "typical" or "average" application often will pass in niche applications. Air sealing and insulation in older homes (built before 1980) is one example that was included in this study, as data were available. Similarly, additional domestic hot water measures may be feasible in homes with a larger number of occupants. For example, drain water heat recovery systems and DHW recirculation systems become more economically attractive with larger household sizes. These latter measures have not been included in the current results as suitable data were not available.

- ***Market Transformation Approaches Warrant Additional Consideration***: The technology cost sensitivity analysis showed that there remains an additional untapped potential savings by 2017 of about 1,100 million m^3 from technically mature measures that do not currently pass the TRC screen. The largest share of these additional potential savings is from air sealing and envelope insulation in existing homes. These measures do not pass the TRC screen as currently defined. However, they provide non-energy benefits such as increased comfort and reduced noise that are not currently captured in the TRC calculation. Similarly, industry specialists emphasized that as insulation levels increase, proper air and moisture sealing is becoming increasingly essential to the long-term structural integrity of Ontario's housing stock. This situation presents both an opportunity and a possible technical issue that may be better addressed through a market transformation approach.

4. COMMERCIAL SECTOR

The Commercial sector includes office and retail buildings, hotels and motels, restaurants, warehouses and a wide variety of small buildings. In this study, it also includes buildings that are often classified as "institutional," such as hospitals and nursing homes, schools and universities.

Throughout this report, use of the word "commercial" includes both commercial and institutional buildings unless otherwise noted.

4.1 APPROACH

The detailed end-use analysis of energy efficiency opportunities in the Commercial sector employed two linked modelling platforms: **CEEAM** (Commercial Energy and Emissions Analysis Model), a Marbek in-house simulation model developed in conjunction with Natural Resources Canada (NRCan) for modelling natural gas use in commercial/institutional building stock, and **CSEEM** (Commercial Sector Energy End-use Model), an in-house spreadsheet-based macro model.

The major steps in the general approach to the study were outlined earlier in Section 1.4 (Approach). Specific procedures for the Commercial sector were as follows:

- **Modelling of Base Year –** Marbek compiled data that defines "where" and "how" natural gas is currently used in existing commercial buildings. The consultants then created building energy use simulations for each type of commercial building and calibrated the models to reflect actual Enbridge customer sales data. Estimated savings for the Other Commercial Buildings category were derived from the results of the modelled segments. They did not directly model that category because it is extremely diverse and the natural gas use of individual facility types is relatively small. The consultant's model produced a close match with actual Enbridge sales data.

- **Reference Case Calculations –** For the Commercial sector, Marbek developed detailed profiles of new buildings in each of the building segments, estimated the growth in building stock and estimated "natural" changes affecting Natural gas consumption over the study period. As with the Base Year calibration, the consultant's projection closely matches the Enbridge 2007 forecast of future natural gas requirements.

- **Assessment of DSM Measures** - To estimate the economic and achievable natural gas savings potentials, the consultants assessed a wide range of commercially available DSM measures and technologies such as:

    - Measures to improve building envelope efficiency
    - Measures to reduce domestic hot water use, including solar hot water systems
    - Upgraded heating and ventilating systems
    - Improved construction in new buildings
    - Efficient cooking appliances.

4.2 COMMERCIAL NATURAL GAS SAVINGS POTENTIAL

A summary of the levels of annual natural gas consumption and potential natural gas savings contained in each of the Commercial sector forecasts addressed by the study are presented in Exhibits 4.1 to 4.3 and discussed briefly in the sub sections that follow.

Exhibit 4.1: Graphic of Forecast Results for the Enbridge Service Area – Annual Natural Gas Consumption, Commercial Sector (million m^3/yr)

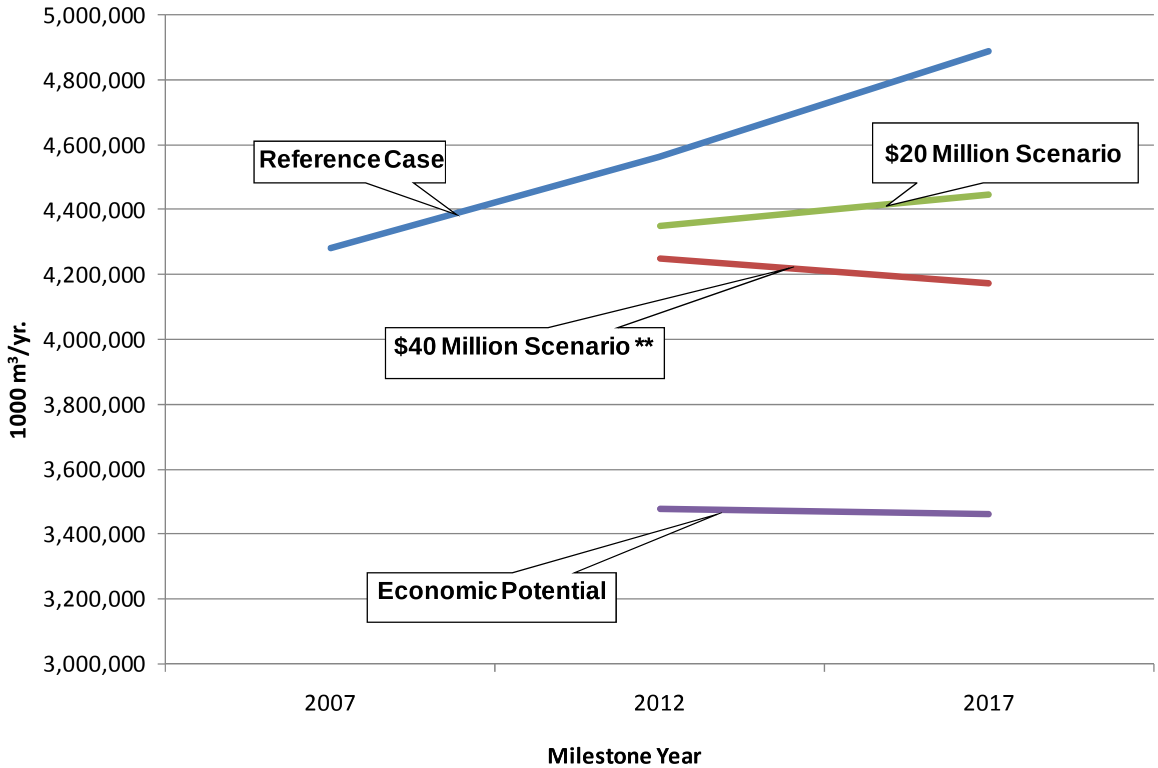


Exhibit 4.2: Summary of Forecast Results for the Total Enbridge Service Area - Annual Natural Gas Consumption, Commercial Sector (million m^3/yr)

Milestone Year	Annual Consumption in Commercial Sector (million m^3/yr.)					
	Reference Case	Economic Potential	Achievable Potential			
			$20M Scenario	$40M Scenario*	$60M Scenario	Financially Unconstrained
2007	4,281					
2012	4,561	3,479	4,350	4,251	**	4,251
2017	4,888	3,461	4,447	4,172	**	4,172

Note: Estimated annual program costs for implementing all cost-effective Commercial sector measures is $10.9 million, moderately less than the $12 million allocated to the commercial sector in the $40 million DSM scenario. Based on the Achievable workshop results, no additional savings were identified in the $60 million or Financially Unconstrained scenarios, while maintaining a positive TRC.

Exhibit 4.3: Summary of Forecast Results for the Total Enbridge Service Area – Achievable Natural Gas Savings in Milestone Years, Commercial Sector (million m^3/yr. and % Relative to Economic Potential Scenario)

Milestone Year	Natural Gas Savings (million m^3/yr., % Relative to Economic Potential)				
	Economic Potential	Achievable Potential			
		$20M Scenario	$40M Scenario*	$60M Scenario	Financially Unconstrained
2012	1,082	212	310	**	310
2017	1,427	440	715	**	715
2012		20%	29%	**	29%
2017		31%	50%	**	50%

Note**:** Natural gas savings in the milestone years represent the potential reduction in gas use in that year as a result of DSM measures implemented in the period. Based on the Achievable workshop results, no additional savings were identified in the $60 million or Financially Unconstrained scenarios, while maintaining a positive TRC.

4.3 BASE YEAR NATURAL GAS USE

In the Base Year of 2007, the Commercial sector in Enbridge's total service area consumed about 4,200,439,000 m^3. The Central service region accounts for approximately 78% of the total commercial sector sales shown in Exhibit 4.4; the Eastern service region accounts for the remaining 22%.

Among the modelled sub sectors shown in Exhibit 4.4, high-rise apartments, mid-rise apartments and large offices are the three largest natural gas users.

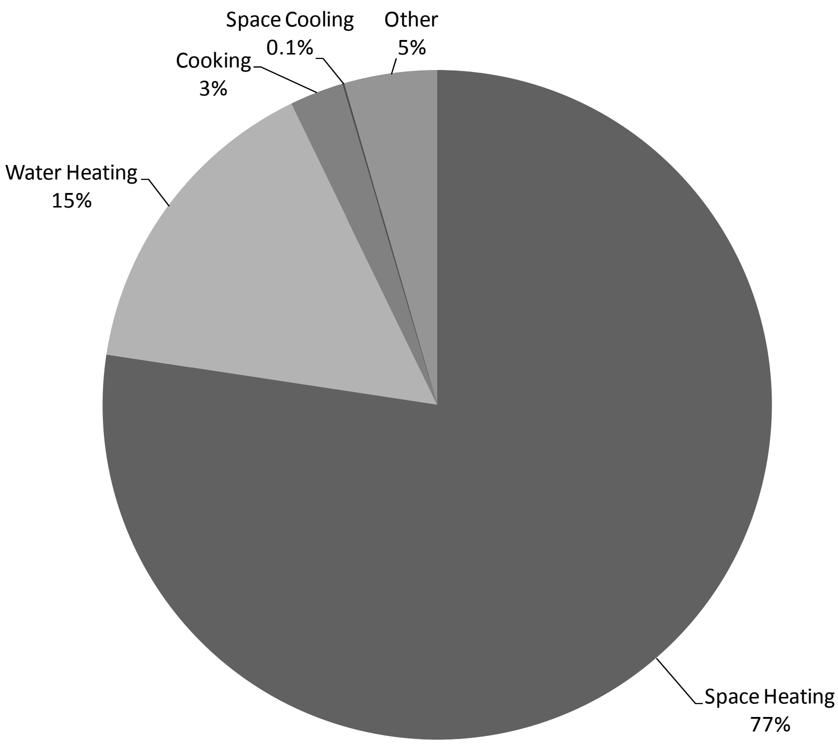
The Other Commercial Buildings sub sector, which is also a large natural gas user, includes buildings that do not fit into any of the remaining sub sectors listed in Exhibit 4.4. These include buildings used for recreational purposes, religious buildings, laundromats, gas stations/car washes, institutional buildings such as correctional facilities, and numerous other building types. Finally, the "Other" sub sector shown in Exhibit 4.4 includes Enbridge customer accounts with missing or unsubstantiated Standard Industrial Classification (SIC) code data. These accounts are classified as "not found" or are unlabelled in the Enbridge sales database.

Exhibit 4.4: Base Year Commercial Sector Natural Gas Use for the Total Enbridge Service Area (1000 m^3/yr)

Sub Sector	Space Heating	Water Heating	Cooking	Space Cooling	Other	Total
Large Office	326,437	34,368	1,431	1,695	53,675	417,606
Small Office	203,775	16,956	691	0	10,360	231,782
Strip Mall	122,794	11,696	5,322	0	6,652	146,464
Retail Services	133,496	8,610	4,366	0	5,458	151,930
Food Retail	62,786	6,173	4,151	0	865	73,975
Large Hotel	20,296	11,489	2,246	232	2,215	36,478
Hotel/Motel	4,239	3,638	97	0	730	8,705
Hospital	78,360	14,835	1,844	503	7,674	103,217
Nursing Home	26,511	8,913	1,993	0	2,835	40,252
School	115,427	7,666	1,789	0	844	125,725
University/College	111,654	15,488	3,742	973	7,128	138,985
Restaurant/Tavern	69,334	27,949	46,130	0	582	143,996
Warehouse/Wholesale	248,854	12,254	510	0	10,195	271,813
Highrise Apartment	578,820	195,990	2,575	0	20,597	797,981
Midrise Apartment	214,163	85,405	844	0	4,222	304,634
Other Commercial Buildings						250,838
Other						956,055
Total	2,316,948	461,429	77,731	3,403	134,034	4,200,439

Exhibit 4.5 shows that space heating accounts for about 77% of total commercial sector natural gas use. Domestic hot water (DHW) accounts for about 15% of the total natural gas use, followed by cooking (3%). A variety of other miscellaneous end uses accounts for the remaining natural gas consumption.

Exhibit 4.5: Base Year Commercial Sector Natural Gas Use for the Total Enbridge Service Area, by End Use[18]



4.4 REFERENCE CASE

In the absence of new DSM initiatives, the study estimates that natural gas consumption in the Commercial sector will grow from 4,200,439,000 $m^{3/}$yr in 2007 to about 4,795,278,000 $m^{3/}$yr in 2017. This represents an overall growth of about 14.2 % in the period and compares very closely with Enbridge‘s own forecast, which also includes consideration of the impacts of “natural conservation.”

Exhibit 4.6 (overleaf) shows the forecast levels of Commercial sector natural gas consumption for the entire Enbridge service area. The results are presented for each milestone year and end use.

[18] The pie chart in Exhibit 4.5 presents percentage of gas consumption by end use for modelled buildings only; the sub sectors “Other Commercial Buildings” and “Other” are included in the total load of the preceding Exhibits, but not included in the pie chart.

Exhibit 4.6: Commercial Sector Reference Case Natural Gas Use for the Total Enbridge Service Area, by Building Type, End use and Milestone Year (1000m^3/yr)

Building Type	Milestone Year	Total	Space Heating	Water Heating	Cooking	Space Cooling	Other
Large Office	2007	417,606	326,437	34,368	1,431	1,695	53,675
	2012	448,243	351,297	37,481	1,617	1,695	56,153
	2017	485,213	381,295	41,238	1,841	1,695	59,143
Small Office	2007	231,782	203,775	16,956	691	0	10,360
	2012	248,787	218,283	18,450	782	0	11,273
	2017	269,334	235,813	20,254	892	0	12,375
Strip Mall	2007	146,464	122,794	11,696	5,322	0	6,652
	2012	157,209	131,547	12,702	5,760	0	7,200
	2017	170,125	142,068	13,911	6,287	0	7,859
Retail Services	2007	151,930	133,496	8,610	4,366	0	5,458
	2012	163,076	142,890	9,493	4,753	0	5,941
	2017	176,550	154,245	10,561	5,220	0	6,525
Food Retail	2007	73,975	62,786	6,173	4,151	0	865
	2012	79,403	67,234	6,713	4,515	0	941
	2017	85,958	72,606	7,365	4,955	0	1,032
Large Hotel	2007	36,478	20,296	11,489	2,246	232	2,215
	2012	39,154	21,465	12,625	2,399	232	2,433
	2017	42,419	22,891	14,011	2,585	232	2,700
Hotel/Motel	2007	8,705	4,239	3,638	97	0	730
	2012	9,343	4,562	3,908	105	0	768
	2017	10,108	4,949	4,231	114	0	814
Hospital	2007	103,217	78,360	14,835	1,844	503	7,674
	2012	110,789	83,801	16,268	2,005	544	8,171
	2017	119,980	90,405	18,007	2,201	593	8,774
Nursing Home	2007	40,252	26,511	8,913	1,993	0	2,835
	2012	43,206	28,499	9,571	2,140	0	2,996
	2017	46,727	30,869	10,355	2,315	0	3,188
School	2007	125,725	115,427	7,666	1,789	0	844
	2012	134,949	123,493	8,565	1,964	0	926
	2017	146,195	133,329	9,661	2,178	0	1,027
University/College	2007	138,985	111,654	15,488	3,742	973	7,128
	2012	149,181	119,911	16,697	4,043	973	7,558
	2017	161,417	129,818	18,148	4,404	973	8,074
Restaurant/Tavern	2007	143,996	69,334	27,949	46,130	0	582
	2012	154,560	74,095	30,167	49,671	0	627
	2017	167,192	79,788	32,819	53,904	0	681
Warehouse/Wholesale	2007	271,813	248,854	12,254	510	0	10,195
	2012	291,754	266,608	13,413	559	0	11,175
	2017	316,025	288,215	14,825	618	0	12,367
Highrise Apartment	2007	797,981	578,820	195,990	2,575	0	20,597
	2012	839,325	604,815	209,824	2,743	0	21,943
	2017	883,072	632,322	224,463	2,921	0	23,367
Midrise Apartment	2007	304,634	214,163	85,405	844	0	4,222
	2012	320,418	224,504	90,495	945	0	4,474
	2017	337,028	235,387	95,852	1,051	0	4,738
Other Commercial Buildings	2007	250,838					
	2012	267,272					
	2017	286,406					
Other	2007	956,055					
	2012	1,018,655					
	2017	1,091,528					
Total	2007	4,200,439	2,316,948	461,429	77,731	3,403	134,034
	2012	4,475,324	2,463,003	496,371	84,000	3,444	142,579
	2017	4,795,278	2,633,999	535,700	91,488	3,493	152,664

4.5 ASSESSMENT OF ENERGY EFFICIENCY MEASURES

The study assessed over 40 potential energy efficiency measures. A summary of the screening results for the energy-efficiency measures is presented in Exhibit 4.7. Due to the number of measures assessed, Exhibit 4.7 shows only the results for options in the Central service region.

Exhibit 4.7: Summary of Measure TRC Screening Results Commercial Sector Energy-efficiency Options – Central Region

Measure Name	Target Market			Simple Payback (Yrs)	B/C Ratio
	Sub Sector(s)	Vintage	Full/ Incr		
High-Performance Glazings	All	E	I	5.3	1.56
Super High-Performance Glazings	All	E	I	15.9	0.52
Wall Insulation	All	E	I	28.7	0.25
Roof Insulation	All	E	I	7.1	1.00
Air Sealing	All	E	F	3.5	0.92
Air Curtains	All	E	F	1.1	5.52
Condensing Boiler - Baseline: Standard Boiler - 1,500 FLE hours	All	E	I	5.0	1.58
Condensing Boiler - Baseline: Near-condensing - 1,500 FLE hours	All	E	I	7.6	1.04
Near Condensing Boiler - Baseline: Standard Boiler - 1,500 FLE hours	All	E	I	1.8	4.33
Condensing Unit heater - Baseline: Standard efficiency - 1,500 FLE hours	All	E	I	2.3	2.96
High-Efficiency Rooftop Unit - Baseline: Standard efficiency - 1,500 FLE hours	All	E	I	2.1	2.96
Condensing Rooftop Unit - Baseline: Standard efficiency - 1,500 FLE hours	All	E	I	4.8	1.28
Gas Absorption Heat Pump - Baseline: standard efficiency boiler - 1,500 FLE hours	All	E	I	2.7	2.29
Steam Plant Efficiency Measures	All	E	F	1.2	4.00
HVLS Destratification Fans	All	E	F	3.4	1.77
Heat Reflector Panels	All	E	F	3.2	2.10
Programmable Heating Controls	All	E	F	2.3	2.72
Heat Recovery	All	E	F	3.2	1.91
Demand Controlled Ventilation	All	E	F	1.5	2.87
Demand Control Kitchen Ventilation	All	E	F	1.8	3.69
Condensing Furnace	All	E	I	2.4	2.81
Ground Source Heat Pumps	All	E	I	24.6	0.61
Solar Preheated Make-up Air	All	E	F	11.5	0.62
Condensing Water Heater - Baseline: standard efficiency - 1,000 FLE hours	All	E	I	3.9	1.83
Condensing Storage Water Heater - Baseline: standard efficiency - 1,000 FLE hours	All	E	I	3.1	1.79
Tankless Water Heater - Baseline: standard efficiency - 1,000 FLE hours	All	E	I	5.5	1.19
Solar Weater Heating System - Baseline: standard efficiency - 1,000 FLE hours	All	E	F	19.1	0.33
Drainwater Heat Recovery - 10 minute shower, 3 times per day	All	E	I	9.2	0.70
Low-Flow Faucet Aerators - 3 min/day	All	E	F	0.4	9.53
Low-Flow Showerheads - 10 min/day	All	E	F	0.3	12.45
Pre-Rinse Spray Valve - 40 min/day	All	E	F	0.3	8.42
High-Efficiency Gas Griddle	All	E	I	5.1	0.87
High-Efficiency Gas Broiler	All	E	I	0.5	8.73
High-Efficiency Gas Oven	All	E	I	7.8	0.56
ENERGY STAR ® Fryer	All	E	I	3.7	1.18
High-Efficiency Gas Range Top	All	E	I	2.4	1.86
Building Recommissioning	All	E	F	0.7	3.31
Advanced Building Automation Systems	All	E	F	2.9	1.47
New Construction - 25% more efficient	All	N	I	3.9	1.78
New Construction - 40% more efficient	All	N	I	4.0	1.74

4.6 ECONOMIC POTENTIAL FORECAST

Under the conditions of the Economic Potential Forecast,[19] the study estimated that natural gas consumption in the Commercial sector would decline to about 3,461,000,000 $m^{3/}$yr by 2017 for the total Enbridge service area. Annual savings relative to the Reference Case are about 1,427,000,000 $m^{3/}$yr by 2017, or about 29%. Further details are provided in Exhibit 4.8, which show the results for both milestone years by sub sector and end use.

4.6.1 Sensitivity Analysis

The Economic Potential results were subjected to a sensitivity analysis around two of the assumptions employed: Technology Cost and inclusion of a value for GHG emissions (as described in Step 5, in Section 1.4). The two sensitivity analyses offer the following insights:

- In the commercial sector, there are relatively few measures that do not pass the economic screen (10 of a total of 40 evaluated measures). Moreover, the additional 10 measures included in the Technology Cost sensitivity analysis provide only modest additional savings relative to the technologies already included in the Economic Potential Forecast.

- The Technology Cost sensitivity analysis identified potential savings of about 1,680 million m^3 in 2017; this compares with identified savings potential of about 1,399 million m^3 in 2017 under the Economic Potential forecast. Hence, the identified Technical savings potential is about 20% greater than that identified in the Economic Potential forecast.

- The GHG adder makes a relatively small difference to the overall avoided cost of energy, and therefore, only one additional measure passes the economic screen. Potential savings are increased by about 2%.

[19] The level of natural gas consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost-effective. In this study, “cost-effective” means that the technology upgrade passes the measure Total Resource Cost (TRC) test

Exhibit 4.8: Natural Gas Savings by Sub Sector, End Use and Milestone Year, Total Enbridge Service Region (1000 m^3/yr.)

Sub sector	Milestone Year	Total	Space Heating	Water Heating	Cooking	Space Cooling	Other
Large Office	2012	114,101	90,126	13,497	113	242	10,124
	2017	144,031	113,723	17,006	257	242	12,804
Small Office	2012	65,476	58,022	5,268	55	0	2,131
	2017	87,524	77,237	7,301	124	0	2,862
Strip Mall	2012	41,587	35,125	4,702	402	0	1,359
	2017	58,335	49,648	5,996	877	0	1,813
Retail Services	2012	40,488	35,764	3,280	331	0	1,113
	2017	55,442	49,157	4,069	728	0	1,488
Food Retail	2012	18,809	16,413	1,902	315	0	179
	2017	25,898	22,340	2,626	691	0	241
Large Hotel	2012	9,626	4,911	4,048	167	33	467
	2017	12,719	6,938	4,750	360	33	638
Hotel/Motel	2012	2,453	1,024	1,281	7	0	141
	2017	3,143	1,456	1,491	16	0	180
Hospital	2012	28,336	21,360	5,414	140	88	1,335
	2017	36,719	28,187	6,499	307	108	1,618
Nursing Home	2012	12,799	8,846	3,260	149	0	543
	2017	15,567	10,640	3,910	323	0	694
School	2012	29,841	26,668	2,865	137	0	171
	2017	41,314	37,273	3,509	304	0	229
University/College	2012	38,890	31,826	5,369	282	139	1,275
	2017	51,299	42,790	6,189	614	139	1,568
Restaurant/Tavern	2012	36,898	22,790	10,527	3,462	0	118
	2017	48,391	27,877	12,843	7,515	0	156
Warehouse/Wholesale	2012	81,106	75,090	3,815	39	0	2,162
	2017	106,741	98,392	5,306	86	0	2,957
High-rise Apartment	2012	213,867	139,707	69,916	191	0	4,052
	2017	281,577	194,612	81,357	407	0	5,201
Mid-rise Apartment	2012	83,772	51,533	31,358	66	0	815
	2017	110,115	71,733	37,202	146	0	1,033
Other Commercial Buildings	2012	51,397					
	2017	67,753					
Other	2012	212,473					
	2017	280,138					
Total	2012	1,081,920	619,206	166,503	5,855	501	25,983
	2017	1,426,706	832,003	200,055	12,755	521	33,482

4.7 ACHIEVABLE POTENTIAL

As noted previously, Achievable Potential was assessed from two perspectives: [20]

- Potential Savings in Future Natural Gas Consumption: Savings in one year due to the Aggregate impact of measures implemented over the time period of Base Year (2007) to Milestone Year (2012 and 2017). This method calculates the net change in future natural gas supply requirements.

- Potential DSM Program TRC Benefits. [21] Savings due to (only) those measures implemented in one year. This method is used in calculation of the net TRC benefits.

Within each of the above perspectives, the analysis of Achievable Potential was assessed under four different Marketing scenarios:

- One Financially Unconstrained scenario
- Three Financially Constrained scenarios, each limited by a different level of program budget availability.

Further detail related to each of the Marketing scenarios is provided below followed by a summary of results.

4.7.1 Financially Unconstrained DSM Marketing Scenario

The Financially Unconstrained scenario provides an overview of the level of potential natural gas savings that could be achieved if a comprehensive portfolio of DSM programs was launched without any constraint on the availability of program funding, except for the requirement to maintain a positive TRC.

Although the results of this scenario are not constrained by program funding, the results do incorporate consideration of the market constraints identified during the Achievable Potential workshop, such as product and service availability and customer transaction costs.

This scenario, therefore, provides a high-level estimate of the upper level of natural gas savings that could be achieved by Enbridge's commercial customers over the nine-year period beginning in 2009 and ending in 2017. It also provides Enbridge's DSM program personnel with a view of the relative potential contribution of individual sub sectors, end uses, technologies and service regions.

[20] See definition of savings as provided in Step 6, page 7.

[21] The annual savings presented do not explicitly address the potential impact of free riders at the level of individual program measure. However, the Reference Case 3 does include an estimate of the impact of natural conservation over the study period, by end use (i.e., an estimate of natural gas savings that would occur in the absence of additional Enbridge DSM programs). Hence, the inclusion of natural conservation in the study's Reference Case does address some, but not necessarily all, free rider and spillover impacts. A more detailed assessment of free rider and spillover impacts is practical only as part of a detailed program design, which is beyond the scope of this study.

Major Assumptions: Financially Unconstrained Scenario

- All measures that pass the measure TRC screen are included
- No program financial limit is set, except that all measures must continue to pass the measure TRC screen
- Participation rates for each measure are based on the workshop results, which consider both market barriers and potential promotional strategies.

Exhibit 4.9 provides details on the program costs assumed for each measure.

Exhibit 4.9: Summary of Program Cost Assumptions, Financially Unconstrained Scenario[22]

Measure Name	Fixed Program Costs per bundle ($/yr.)	Incentive Amount ($/m³ saved)	Simple Payback After Incentive (yrs.)
High-Performance Glazings	$ 75,000	$ 0.332	4.6
Roof insulation		$ 0.332	6.4
Air Curtains	$ 14,000	$ 0.277	0.9
Condensing Boiler - Baseline: Standard Boiler	$ 60,000	$ 0.221	4.5
Condensing Boiler - Baseline: Near Condensing		$ 0.221	7.1
Near-Condensing Boiler		$ 0.221	1.3
Condensing Unit Heater	$ 60,000	$ 0.332	1.6
High-Efficiency Rooftop Unit		$ 0.277	1.5
Condensing Furnace		$ 0.221	1.9
Demand Controlled Ventilation	$ 70,000	$ 0.332	0.8
Demand Control Kitchen Ventilation		$ 0.508	1.1
Heat Recovery		$ 0.332	2.5
Condensing Water Heater	$ 40,000	$ 0.332	3.3
Condensing Storage Water Heater		$ 0.332	2.4
Low-Flow Faucet Aerators	$ 2,500	$ 0.042	0.4
Low-Flow Showerheads		$ 0.042	0.3
Pre-Rinse Spray Valve	$ 40,000	$ 0.300	0.1
High-Efficiency Broiler	$ 40,000	$ 0.332	-0.2
ENERGY STAR® Fryer		$ 0.332	3.0
High-Efficiency Range		$ 0.332	1.7
Building Recommissioning	$ 600,000	$ 0.249	0.6
Advanced Building Automation Systems		$ 0.249	2.7
Steam Plant Efficiency Measures		$ 0.249	0.7
HVLS Destratification Fans	$ 20,000	$ 0.332	2.7
New Construction - 25% More Efficient	$ 735,000	$ 0.159	3.8
New Construction - 40% More Efficient		$ 0.159	3.9

[22] Salary and related overhead costs are not included in program cost estimates. Also, the incentive levels are capped at 100% of the indicated measure cost.

4.7.2 Financially Constrained DSM Marketing Scenarios

These DSM scenarios provide estimates of the potential impacts of increasingly larger annual DSM budgets, which as noted previously were set at $20, $40 and $60 million, annually. Within each of these budgets, 30% of the funding is allocated to the Commercial sector for the purposes of this analysis.

The financially constrained scenarios include the following DSM costs:

- **Fixed Program Costs**: This includes costs for items such as newspaper advertisements, preparation of information and marketing materials, training workshops, contractor certifications, etc. These program cost elements are not expected to vary significantly if the number of installations of the measure changed. Estimates for these cost items were provided by Enbridge personnel, based on current and previous experience with similar DSM measures. In each case, these costs are expressed as dollars of program spending per year. For each of the measures, fixed program costs were estimated for both the CML and Financially Unconstrained Marketing scenarios. Salary and related overhead costs are not included.

- **Incentive Costs**: These costs would include any costs that vary directly according to the number of installations of the measure. Incentive amounts vary by measure and are expressed as dollars per m^3 gas saved.

Exhibit 4.10 provides details on the program costs assumed for each measure.

Exhibit 4.10: Summary of Program Cost Assumptions, CML Scenario[23]

Measure Name	Fixed Program Costs per bundle ($/yr.)	Incentive Amount ($/m³ saved)	Simple Payback After Incentive (yrs.)
High-Performance Glazings	$ 50,000	$ 0.100	5.1
Roof Insulation		$ 0.100	6.9
Air Curtains	$ 7,000	$ 0.100	1.0
Condensing Boiler - Baseline: Standard Boiler	$ 40,000	$ 0.100	4.7
Condensing Boiler - Baseline: Near Condensing		$ 0.100	7.3
Near-Condensing Boiler		$ 0.100	1.6
Condensing Unit Heater	$ 40,000	$ 0.100	2.1
High-Efficiency Rooftop Unit		$ 0.100	1.9
Condensing Furnace		$ 0.100	2.2
Demand Controlled Ventilation	$ 35,000	$ 0.100	1.3
Demand Control Kitchen Ventilation		$ 0.152	1.6
Heat Recovery		$ 0.100	3.0
Condensing Water Heater	$ 20,000	$ 0.100	3.7
Condensing Storage Water Heater		$ 0.100	2.9
Low-Flow Faucet Aerators	$ 1,000	$ 0.025	0.4
Low-Flow Showerheads		$ 0.025	0.3
Pre-Rinse Spray Valve	$ 20,000	$ 0.120	0.2
High-Efficiency Broiler	$ 20,000	$ 0.100	0.3
ENERGY STAR® Fryer		$ 0.100	3.5
High-Efficiency Range		$ 0.100	2.1
Building Recommissioning	$ 400,000	$ 0.100	0.7
Advanced Building Automation Systems		$ 0.100	2.8
Steam Plant Efficiency Measures		$ 0.100	1.0
HVLS Destratification Fans	$ 10,000	$ 0.100	3.2
New Construction - 25% More Efficient	$ 490,000	$ 0.064	3.8
New Construction - 40% More Efficient		$ 0.064	3.9

[23] Salary and related overhead costs are not included in program cost estimates. Also, the incentive levels are capped at 100% of the indicated measure cost.

4.7.3 Achievable Potential Savings – Future Natural Gas Consumption

Exhibits 4.11 and 4.12 present a summary of the Achievable Potential savings in future natural gas consumption relative to the Reference Case levels. For illustration, the results of the Financially Unconstrained scenario are shown. Selected highlights are provided below.

- Exhibit 4.11 shows that total Commercial sector natural gas savings in 2017 are estimated to be approximately 715 million m^3/yr. This represents a savings of approximately 15%, relative to the Reference Case and is equal to approximately 50% of the savings identified in the Economic Potential Forecast. The Central service region accounts for about 81% of the identified potential.

- Exhibit 4.12 shows the results by sub sector and end use for the Enbridge Service Area. As illustrated, the majority of savings are associated with the space heating end use (74%), while three sub sectors (High-rise Apartment, Other Buildings and Large Office) account for nearly 50% of total savings under this scenario.

Exhibit 4.11: Natural Gas Savings by Service Region and Milestone Year, Financially Unconstrained Scenario (1000 m^3/yr.)

Milestone Year	Central service region (1000 m^3/yr.)	Eastern service region	Total	% Savings Relative to Ref Case
2012	251,047	59,149	310,196	7%
2017	580,405	135,008	715,414	15%
% Savings 2017 Re: Reference Case	14%	15%	15%	
% Savings 2017 Re: Total	81%	19%	100%	

Exhibit 4.12: Natural Gas Savings by End Use and Milestone Year for the Total Enbridge Service Area, Financially Unconstrained Scenario (1000 m^3/yr.)

Sub sector	Milestone Year	Total	Space Heating	Water Heating	Cooking	Space Cooling	Other
Large Office	2012	34,632	27,494	4,150	38	80	2,869
	2017	77,260	61,159	9,291	139	163	6,508
Small Office	2012	16,742	14,716	1,480	18	0	528
	2017	38,979	34,105	3,552	66	0	1,256
Strip Mall	2012	9,639	7,945	1,252	133	0	310
	2017	23,734	19,625	2,896	462	0	751
Retail Services	2012	11,390	9,977	994	112	0	306
	2017	26,898	23,579	2,203	392	0	725
Food Retail	2012	5,404	4,659	582	115	0	49
	2017	12,779	10,884	1,378	402	0	116
Large Hotel	2012	2,815	1,387	1,238	53	11	126
	2017	6,510	3,332	2,672	181	22	302
Hotel/Motel	2012	668	265	364	2	0	36
	2017	1,524	641	793	9	0	82
Hospital	2012	8,811	6,449	1,831	53	29	449
	2017	20,450	15,204	3,975	185	66	1,020
Nursing Home	2012	3,833	2,637	999	48	0	148
	2017	8,430	5,722	2,199	167	0	342
School	2012	9,564	8,507	956	50	0	52
	2017	22,720	20,328	2,092	177	0	123
University/College	2012	12,006	9,597	1,852	95	51	412
	2017	27,617	22,293	3,966	328	103	926
Restaurant/Tavern	2012	10,386	6,056	3,140	1,161	0	30
	2017	24,479	13,326	7,068	4,015	0	71
Warehouse/Wholesale	2012	20,479	19,002	983	13	0	480
	2017	47,430	43,809	2,400	45	0	1,175
High-rise Apartment	2012	62,916	39,869	21,853	64	0	1,131
	2017	144,451	94,195	47,459	217	0	2,580
Mid-rise Apartment	2012	24,969	14,521	10,197	22	0	228
	2017	57,094	34,105	22,393	79	0	517
Other Commercial Buildings	2012	14,832					
	2017	34,177					
Other	2012	61,111					
	2017	140,882					
Total	2012	310,196	173,080	51,870	1,979	171	7,153
	2017	715,414	402,307	114,336	6,865	355	16,492

4.7.4 Potential DSM Program TRC Benefits

Exhibits 4.13, 4.14 and 4.15 present the results for the milestone year 2017. As illustrated, annual Commercial sector program spending of approximately $10.4 million in 2017 is estimated to result in the installation of measures providing approximately 67 million m^3/year in natural gas savings[24] and approximately $203 million in TRC net benefits. The exhibits also show that annual commercial program spending achieves maximum results at expenditures of $10.4 million in 2012 and $10.9 million in 2017, which is below the allowable Commercial sector program budget of $12 million. This is because additional cost-effective measures were not available while also maintaining a positive TRC. Additional details are provided in the following exhibits.

- Exhibit 4.13 presents the 2017 results by upgrade technology bundle, including both the current marketing level of participation and the increment from CML to financially unconstrained. For each measure bundle, annual natural gas savings potential, net TRC benefits and annual program costs are presented both individually and cumulatively. The measures are sorted in order of increasing program cost per dollar of TRC benefits. The six measure bundles contributing the most TRC benefits are assigned letters, matching the labels on Exhibits 4.13 and 4.14.

- Exhibit 4.14 presents the 2017 results graphically, with program costs on the vertical axis and net TRC benefits on the horizontal axis. The $6 million annual budget level for commercial program spending is shown as a horizontal line for reference.

- Exhibit 4.15 presents the 2017 results graphically, with program costs on the vertical axis and annual natural gas savings potential on the horizontal axis. The $6 million annual budget level for commercial program spending is shown as a horizontal line for reference.

[24] Note: the savings shown are only for the measures installed in 2017; they do not include the savings in 2017 that occur as a result of measures installed in prior periods.

Exhibit 4.13: Summary Achievable Results** by Measure, for the Enbridge Service Area, 2017 Installations

Reference (Marked on Graphs)	Upgrade Technology/Measures	Scenario	Annual Natural Gas Savings Potential (1000 m^3/yr.)		TRC ($)		Annual Program Costs ($)		Program Costs per Unit	
				Cumulative		Cumulative		Cumulative	per Natural Gas Savings ($/$m^3$)	per TRC Benefits ($/$)
A	DHW - Conservation Measures	CML	8,012	8,012	$ 25,087,338	$ 25,087,338	$ 270,758	$ 270,758	$ 0.034	$ 0.011
B	DHW - Conservation Measures	Aggressive	3,923	11,935	$ 12,269,293	$ 37,356,631	$ 250,043	$ 520,801	$ 0.064	$ 0.020
C	New construction - 40% Better	CML	3,316	15,251	$ 23,953,898	$ 61,310,529	$ 692,096	$ 1,212,896	$ 0.209	$ 0.029
D	New construction - 40% Better	Aggressive	3,131	18,382	$ 22,801,127	$ 84,111,655	$ 760,595	$ 1,973,491	$ 0.243	$ 0.033
E	Space Heating / Other - Recommissioning	CML	21,322	39,704	$ 64,963,918	$ 149,075,574	$ 2,523,683	$ 4,497,174	$ 0.118	$ 0.039
	Space Heating - Ventilation Measures - Heat Recovery	CML	3,149	42,853	$ 5,563,440	$ 154,639,013	$ 363,926	$ 4,861,100	$ 0.116	$ 0.065
	Space Heating - Equipment	CML	3,311	46,164	$ 5,160,942	$ 159,799,955	$ 409,752	$ 5,270,852	$ 0.124	$ 0.079
F	Space Heating / Other - Recommissioning	Aggressive	10,260	56,424	$ 31,251,590	$ 191,051,545	$ 2,754,864	$ 8,025,716	$ 0.268	$ 0.088
	DHW - Equipment Measures	CML	1,391	57,815	$ 1,788,785	$ 192,840,330	$ 158,547	$ 8,184,264	$ 0.114	$ 0.089
	Space Heating - Envelope measures (Conductive)	CML	854	58,670	$ 769,917	$ 193,610,246	$ 135,106	$ 8,319,370	$ 0.158	$ 0.175
	Space Heating - Ventilation Measures - Heat Recovery	Aggressive	2,863	61,533	$ 5,053,834	$ 198,664,080	$ 1,031,819	$ 9,351,189	$ 0.360	$ 0.204
	Space Heating - Envelope measures (Mass transfer)	CML	1,056	62,588	$ 479,097	$ 199,143,177	$ 112,141	$ 9,463,330	$ 0.106	$ 0.234
	Space Heating - Envelope measures (Conductive)	Aggressive	2,975	65,564	$ 2,878,361	$ 202,021,539	$ 1,012,833	$ 10,476,162	$ 0.340	$ 0.352
	Space Heating - Envelope measures (Mass transfer)	Aggressive	1,116	66,679	$ 506,902	$ 202,528,440	$ 316,304	$ 10,792,467	$ 0.283	$ 0.624
	Efficient Food Service Equipment	CML	33	66,713	$ 13,068	$ 202,541,509	$ 13,309	$ 10,805,775	$ 0.401	$ 1.018
	Efficient Food Service Equipment	Aggressive	57	66,770	$ 5,767	$ 202,547,275	$ 49,068	$ 10,854,843	$ 0.854	$ 8.509
								Weighted Average (@ $6M spending):	$ 0.114	$ 0.032
								Weighted Average (all measures):	$ 0.163	$ 0.054

** Savings shown are incremental to those for preceding measures.

Exhibit 4.14: Achievable Potential Supply Curve, 2017 Installations: Program Cost vs. TRC Net Benefits, for the Enbridge Service Area

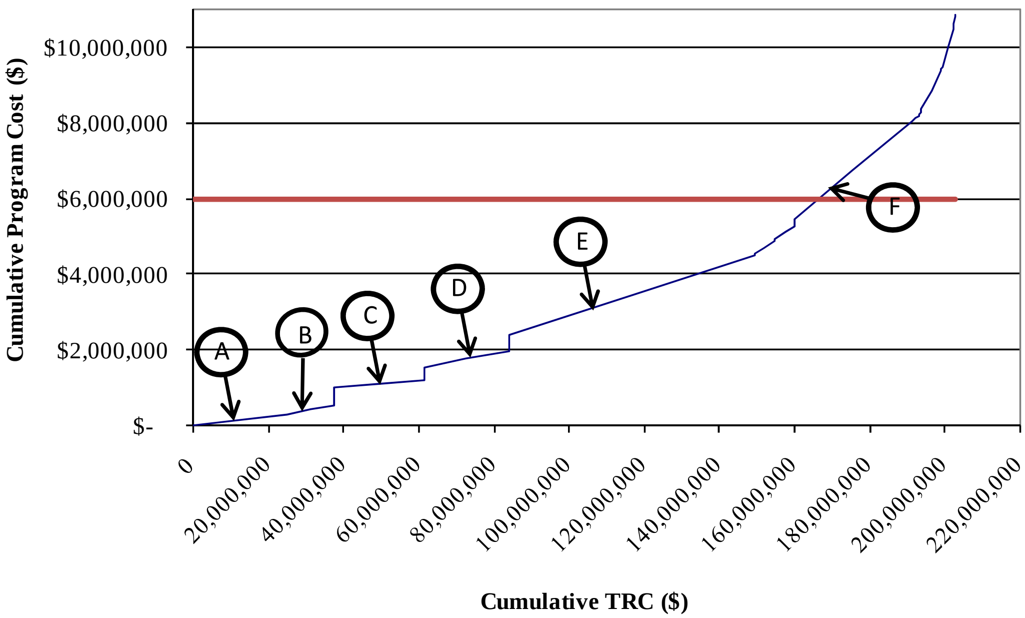
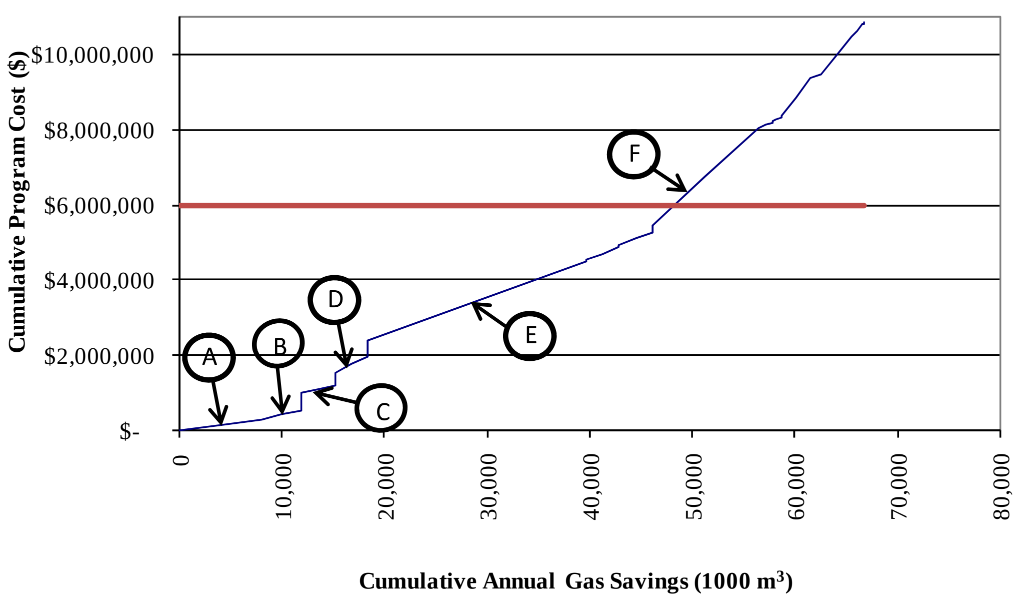


Exhibit 4.15: Achievable Potential Supply Curve, 2017 Installations: Program Cost vs. Annual Natural Gas Savings Potential, for the Enbridge Service Area



4.7.5 Conclusions

Selected highlights are provided below.

- Annual commercial program spending achieves maximum results at expenditures of \$10.4 million in 2012 and \$10.9 million in 2017, which is below the allowable commercial budget of \$12 million. This is because additional cost-effective measures were not available under the conditions defined by this scenario.

- Program costs per dollar of TRC net benefits increase over the study period. This is primarily due to the fact that recommissioning, the largest commercial opportunity, is slightly more expensive on a cost per TRC dollar basis in 2017 than 2012. This reflects a situation in which fixed costs remain constant through time, while yearly savings levels decrease as the most attractive opportunities are realized by the earlier milestone year.

- With commercial program spending of approximately \$10.4 million in 2017, program costs are approximately \$0.16 per m^3 of natural gas savings and \$0.05 per dollar of TRC benefits. This compares with recent Enbridge monitoring and evaluation results[25] of \$0.11 per m^3 of gross natural gas savings (\$0.14 m^3 net of free riders) in 2007.

- For two measure groups (space heating equipment and water heating equipment), savings for the year 2017 are greater under the Financially Constrained scenarios than under the Financially Unconstrained scenario. This reflects a situation in which the majority of the opportunity is realized in early years under the Financially Unconstrained scenario, while savings “ramp up” slowly under the Financially Constrained scenarios.

- Recommissioning represents the largest contribution to annual savings in both milestone years. Other measures that offer particularly significant natural gas savings potential in both milestone years include hot water conservation measures and efficient new construction.

[25] Enbridge Gas, 2007 LRAM Post Audit Results.

4.8 ADDITIONAL OBSERVATIONS

In addition to the preceding conclusions, three additional observations warrant note as they may affect future Commercial sector program strategies. They include:

- ***Rate of measure implementation has a large effect on overall savings:*** For measures that pass the TRC screen on an incremental cost basis, low participation rates in early milestone years create a significant "lost opportunity." This is particularly relevant to the replacement of equipment with a very long life (i.e. space heating equipment), building renovations such as envelope improvements, and new building construction. The gap between Economic Potential and Achievable Potential savings presented in this study is due in large part to this significant lost opportunity that occurs in early milestone years.

- ***Savings arising from full cost measures may be delayed without eroding overall potential:*** This is a corollary of the above point, and most pertinent to the discussion of the largest opportunity identified in this study, recommissioning. As recommissioning passes the TRC screen at full cost, eligible buildings which are not recommissioned remains as future opportunities, while incremental cost opportunities which are not exploited represent lost opportunities. This may be especially relevant to programming strategy during periods of economic downturn, when building owners and managers may be less likely to implement measures despite an attractive payback.

- ***Market transformation approaches warrant additional consideration:*** The technology cost sensitivity analysis showed that there remains an additional untapped potential savings by 2017 of about 269 million m^3 from technically mature measures that do not currently pass the TRC screen. The largest share of these additional potential savings are from air sealing and envelope upgrades, including wall insulation and more energy efficient glazing measures in existing buildings. These measures do not pass the TRC screen as currently defined. However, they provide non-energy benefits such as increased comfort and reduced noise that are not currently captured in the TRC calculation. In addition, industry specialists emphasized that some emerging technologies, such as solar preheated make-up air may be better addressed in a market transformation context, as they provide "soft" benefits, such as visible contribution to corporate greening goals, that are not included in the TRC calculation.

5. INDUSTRIAL SECTOR

The Industrial sector consists of the seven largest natural gas consuming industries within the Enbridge service area plus an additional miscellaneous category that combines eight smaller industry groups. The seven large industries, which are the primary focus of this study, are: Non-metallic Mineral Products, Food Products, Paper Manufacturing, Refined Petroleum and Coal, Chemical Manufacturing, Primary Metals and Fabricated Metals.

5.1 APPROACH

The detailed end-use analysis of energy efficiency opportunities in the Industrial sector employed Marbek's customized macro model. The model is organized by major industrial sub sector and major end use.

Natural gas end-use profiles were developed for the seven sub sectors described above. The profiles map proportionally how much natural gas is used by each of the end uses for each sub sector. These profiles represent the sub sector archetypes and are used in the model to calculate the natural gas used by each end use for each sub sector.

The major steps in the general approach to the study are outlined in Section 1.4 above (Approach). Specific procedures for the Industrial sector were as follows:

- **Modelling of Base Year –** The consultants compiled Base Year data on the industrial sector from a variety of sources, including Enbridge's customer information, the study team's own energy assessment experience within many of the sub sectors and secondary data sources. The macro model results produced a close match with actual Enbridge sales data.

- **Reference Case Calculations -** The consultants prepared a Reference Case forecast based on projected growth forecasts provided by Enbridge, which includes anticipated closing of existing facilities and opening of new facilities.

- **Assessment of DSM Measures –**To estimate the economic and achievable natural gas savings potentials, the consultants assessed a wide range of commercially available energy efficiency measures and technologies such as:

  - Integrated control systems
  - More efficient boiler, steam and hot water systems
  - Efficient process heating technologies
  - Efficient space heating and ventilation, including solar thermal technologies.

5.2 INDUSTRIAL NATURAL GAS SAVINGS POTENTIAL

A summary of the levels of annual natural gas consumption and potential natural gas savings contained in each of the Industrial sector forecasts addressed by the study are presented in Exhibits 5.1 to 5.3 and discussed briefly in the sub sections that follow.

Exhibit 5.1: Graphic of Forecast Results for the Enbridge Service Area – Annual Natural Gas Consumption, Industrial Sector (million m^3/yr)

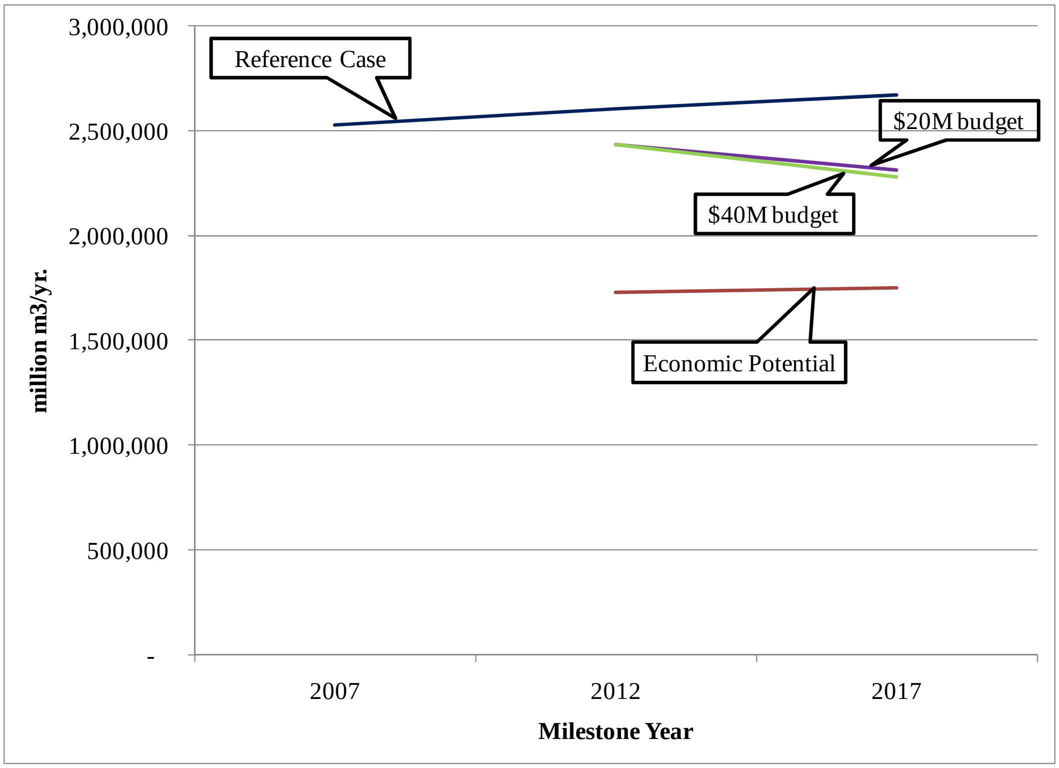


Exhibit 5.2: Summary of Forecast Results for the Total Enbridge Service Area - Annual Natural Gas Consumption, Industrial Sector (million m^3/yr)

Milestone Year	Annual Consumption in Industrial Sector (million m^3/yr)					
	Reference Case	Economic Potential	Achievable Potential			
			$20M Scenario*	$40M Scenario**	$60M Scenario	Financially Unconstrained
2007	2,530					
2012	2,604	1,726	2,433	***	***	2,433
2017	2,671	1,751	2,316	2,278	****	2,278

Exhibit 5.3: Summary of Forecast Results for the Total Enbridge Service Area – Achievable Natural Gas Savings in Milestone Years, Industrial Sector (million m^3/yr. and % Relative to Economic Potential Scenario)

Milestone Year	Natural Gas Savings (million m^3/yr., Relative to Economic Potential %)				
	Economic Potential	Achievable Potential			
		$20M Scenario*	$40M Scenario**	$60M Scenario	Financially Unconstrained
2012	877	171	***	***	171
2017	919	355	392	****	392
2012		19%	***	***	19%
2017		39%	43%	****	43%

Note**:** Natural gas savings in the milestone years represent the potential reduction in gas use in that year as a result of DSM measures implemented in the period.

[*] Estimated annual program costs for implementing all cost-effective measures is $3.1 million in 2012, moderately less than the $4 million allocated to the industrial sector in the $20 million DSM scenario. Results reported are for $3.1 million, and represent the maximum savings for the achievable scenario in 2012.

[**] Estimated annual program costs for implementing all cost-effective measures is $4.4 million in 2017, significantly less than the $8 million allocated to the industrial sector in the $40 million DSM scenario. Results reported are for $4.4 million, and represent the maximum savings for the achievable scenario in 2017.

[***] Maximum measure implementation rates are achieved in the $20 million scenario in 2012. Based on the Achievable workshop results, no additional savings were identified in the $40 million, $60 million or Financially Unconstrained scenarios, while maintaining a positive TRC.

[****] Maximum measure implementation rates are achieved in the $40 million scenario in 2017. Based on the Achievable workshop results, no additional savings were identified in the $60 million or Financially Unconstrained scenarios, while maintaining a positive TRC.

5.3 BASE YEAR NATURAL GAS USE

In the Base Year of 2007, the Industrial sector in Enbridge's total service area consumed about 2,529,979,000 m^3. This volume excludes natural gas used for power generation, co-generation and industrial feedstock, as these uses of natural gas are beyond the scope of this study.

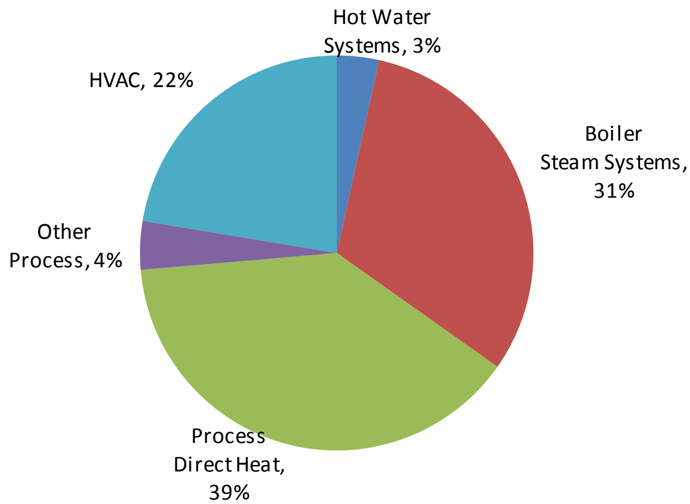
The 7 core industry sub sectors shown in Exhibit 5.4 account for 67% of the total industry natural gas consumption; 88% of the total industry natural gas consumption occurs in the central service region.

Exhibit 5.4: Base Year Industrial Sector Natural Gas Consumption for the Total Enbridge Service Area (1,000 m^3/yr.)

Sub Sector	End Use						
	Hot Water Systems	Boiler Steam Systems	Process Direct Heat	Other Process	HVAC	Total	Percentage of Total (%)
Non-metallic Mineral Product Mfg.	6,655	39,798	235,793	12,578	37,935	332,759	13%
Food Product Mfg.	26,125	156,162	89,772	20,214	34,289	326,563	13%
Paper Manufacturing	5,820	181,547	55,113	5,325	43,182	290,987	11%
Refined Petroleum & Coal	8,556	74,155	165,423	4,563	32,514	285,213	11%
Primary Metal	3,663	21,518	127,953	4,175	25,821	183,131	7%
Fabricated Metal	7,313	34,736	85,927	9,141	45,706	182,822	7%
Chemical	3,514	71,337	57,983	12,966	29,907	175,706	7%
Miscellaneous Mfg.	27,526	222,764	222,175	34,790	326,329	833,584	33%
Total	87,557	792,355	982,895	100,699	566,473	2,529,979	100%
Percentage	3%	31%	39%	4%	22%		

As illustrated in Exhibit 5.5 process direct heat accounts for about 39% of total industrial sector natural gas use. Boiler steam systems account for about 31% of the total natural gas use, followed by heating, ventilation and air conditioning (HVAC), which accounts for about 22%. Other processes and hot water systems account for the remaining natural gas consumption.

Exhibit 5.5: Base Year Industrial Sector Natural Gas Use for the Total Enbridge Service Area, by End Use



5.4 REFERENCE CASE

In the absence of new DSM initiatives, the study estimates that natural gas consumption in the Industrial sector will grow from 2,529,979,000 m$^{3/}$yr in 2007 to about 2,670,651,000 m$^{3/}$yr in 2017. This represents an overall growth of about 5.6% in the period and compares very closely with Enbridge's own forecast, which also includes consideration of the impacts of "natural conservation." Exhibit 5.6 shows the forecast levels of Industrial sector natural gas consumption for the entire Enbridge service area. The results are presented for each milestone year and sub sector.

Exhibit 5.6: Industrial Sector Reference Case Natural Gas Use for the Total Enbridge Service Area, by Sub Sector and Milestone Year (1000 m^3/yr)

	Eastern Region			Central Region			All Regions		
Sub Sector	**2007**	**2012**	**2017**	**2007**	**2012**	**2017**	**2007**	**2012**	**2017**
Non-metallic Mineral Product Mfg.	40,316	41,493	42,557	211,657	217,838	223,426	251,973	259,331	265,983
Food Product Mfg.	26,138	26,901	27,591	300,425	309,198	317,129	326,563	336,098	344,721
Paper Manufacturing	13,393	13,784	14,138	277,594	285,700	293,029	290,987	299,484	307,167
Refined Petroleum & Coal	16,091	16,561	16,986	269,122	276,980	284,085	285,213	293,541	301,071
Primary Metal	44,663	45,968	47,147	138,467	142,510	146,166	183,131	188,478	193,313
Fabricated Metal	18,290	18,824	19,307	164,533	169,337	173,681	182,822	188,161	192,988
Chemical	26,435	27,207	27,905	149,271	153,630	157,571	175,706	180,837	185,476
Miscellaneous Mfg.	121,869	125,428	128,646	711,714	732,496	751,287	833,584	857,924	879,933
Total	307,195	316,165	324,276	2,222,784	2,287,689	2,346,376	2,529,979	2,603,854	2,670,651

5.5 ASSESSMENT OF ENERGY EFFICIENCY MEASURES

The study assessed over 30 potential energy efficiency measures. A summary of the screening results for the energy-efficiency measures is presented in Exhibit 5.7. Due to the number of measures assessed for each sub sector the results shown are for the measures applied to a large technology group in the Chemical sub sector.

Exhibit 5.7: Summary of Measure TRC Screening Results — Example for Chemical Sub Sector, Large Technology Energy-efficiency Options

End Use	Measure	Full/ Incremental	Net Measure TRC	Simple Payback Period (Years)	Benefit/ Cost Ratio
System	Integrated control system	F	$ 772,955	0.8	5.3
	Sub metering, monitoring and targeting	F	$ 373,150	2.8	2.0
Boiler, Steam & Hot Water Systems	Economizers	F	$ 547,220	2.7	2.3
	Blowdown heat recovery	F	$ 207,457	3.3	1.8
	Boiler combustion air preheat	F	$ 570,854	3.2	1.9
	Heat recovery to preheat make-up water	F	$ 1,073,127	2.1	3.2
	Condensing boiler	I	$ 1,597,860	2.0	3.0
	Boiler right sizing and load management	I	$ 2,816,602	N/A	N/A
	High-efficiency burners	F	$ 734,121	2.5	2.6
	Insulation	F	$ 839,968	1.0	5.4
	Advanced boiler controls	F	$ 767,976	1.3	3.9
	Blowdown control	F	-$ 30,664	8.2	0.8
	Boiler water treatment	F	$ 83,769	1.8	2.1
	Boiler maintenance	F	$ 273,377	N/A	2.4
	Minimize deaerator vent losses	F	$ 339,472	2.3	2.8
	Condensate return	F	$ 258,722	4.4	1.5
	Steam trap survey and repair	F	$ 16,243	1.6	1.1
Process Heating (Furnaces/ Kilns/ Ovens/ Dryers)	Exhaust gas heat recovery	F	$ 5,159,494	1.0	5.4
	High-efficiency burners	F	$ 6,518,245	0.7	9.2
	Insulation	F	$ 1,283,871	1.0	5.3
	Advanced heating and process controls	F	$ 2,530,763	1.0	5.0
Other Process	Process heat recovery	F	$ 2,856,281	1.6	3.1
HVAC	Radiant heaters	F	$ 78,369	4.7	1.3
	Automated temperature control	F	$ 2,614	6.7	1.0
	Solar walls	F	-$ 69,729	10.2	0.7
	Ventilation optimization	F	$ 107,538	2.5	2.2
	Warehouse loading dock seals	F	-$ 15,800	6.3	0.7
	Air curtains	F	-$ 5,510	6.1	0.9
	Air compressor heat recovery	F	$ 136,353	3.1	2.1
	Destratification fans	F	$ 16,262	5.5	1.2
	Ventilation heat recovery	F	$ 113,925	2.8	2.0

5.6 ECONOMIC POTENTIAL FORECAST

Under the conditions of the Economic Potential Forecast,[26] the study estimated that natural gas consumption in the Industrial sector would decline to about 1,751,313,000 $m^{3/}$yr by 2017 for the total Enbridge service area. Annual savings relative to the Reference Case are about 919,340,000 $m^{3/}$yr by 2017, or about 34%. %. Further details are provided in Exhibits 5.8 and 5.9, which show the results by sub sector and end use for the milestone years 2012 and 2017, respectively.

Exhibit 5.8: Natural Gas Savings for the Total Enbridge Service Area by Sub Sector and End Use for the Milestone Year 2012, Reference Case vs. Economic Potential (1000 m^3/yr.)

	End Use							
Sub Sector	**System**	**Hot Water Systems**	**Boiler Steam Systems**	**Process Direct Heat**	**Other Process**	**HVAC**	**Total**	
Non-metallic Mineral Product Mfg.	9,505	886	8,797	29,511	784	17,187	66,669	8%
Food Product Mfg.	21,999	4,753	50,613	14,702	1,660	20,280	114,006	13%
Paper Manufacturing	14,467	1,016	52,389	8,505	433	25,486	102,296	12%
Refined Petroleum & Coal	10,759	1,461	22,620	26,589	374	20,290	82,094	9%
Primary Metal	6,908	755	7,345	20,401	344	15,828	51,583	6%
Fabricated Metal	12,316	1,526	11,808	14,487	751	25,749	66,637	8%
Chemical	7,496	611	20,765	9,516	1,067	17,889	57,344	7%
Miscellaneous Mfg.	31,445	5,018	68,431	37,341	2,862	191,669	336,766	38%
Total	114,896	16,026	242,768	161,052	8,275	334,379	877,394	100%
%	13%	2%	28%	18%	1%	38%	100%	

Exhibit 5.9: Natural Gas Savings for the Total Enbridge Service Area by Sub Sector and End Use for the Milestone Year 2017, Reference Case vs. Economic Potential (1000 m^3/yr.)

	End Use							
Sub Sector	**System**	**Hot Water Systems**	**Boiler Steam Systems**	**Process Direct Heat**	**Other Process**	**HVAC**	**Total**	
Non-metallic Mineral Product Mfg.	9,469	1,307	10,480	33,845	778	17,047	72,927	8%
Food Product Mfg.	22,201	5,956	54,287	15,367	1,645	20,071	119,526	13%
Paper Manufacturing	14,412	1,490	62,222	8,823	429	25,203	112,579	12%
Refined Petroleum & Coal	10,719	1,858	24,308	28,865	371	20,105	86,226	9%
Primary Metal	6,882	933	7,916	22,280	343	15,756	54,110	6%
Fabricated Metal	12,429	1,874	12,677	15,775	745	25,516	69,016	8%
Chemical	7,494	750	22,534	9,964	1,059	17,739	59,539	6%
Miscellaneous Mfg.	31,327	6,331	73,973	40,922	2,841	190,022	345,416	38%
Total	114,932	20,499	268,397	175,843	8,211	331,458	919,339	100%
%	13%	2%	29%	19%	1%	36%	100%	

5.6.1 Sensitivity Analysis

The Economic Potential results were subjected to a sensitivity analysis around two of the assumptions employed: Technology Cost and inclusion of a value for GHG emissions (as described in Step 5, in Section 1.4). The two sensitivity analyses offer the following insights:

[26] The level of natural gas consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost-effective. In this study, "cost-effective" means that the technology upgrade passes the measure Total Resource Cost (TRC) test, as discussed previously in Section 1.4.

- In the Industrial sector, the additional measures included in the technology cost sensitivity analysis provide only modest additional savings relative to the technologies already included in the Economic Potential Forecast.

- The sensitivity analysis identified potential savings of about 1,015 million m^3 in 2017; this compares with the identified savings potential of about 919 million m^3 in 2017 under the Economic Potential Forecast. Hence, the identified technical savings potential is about 12% greater than that identified in the Economic Potential Forecast.

- The GHG adder makes a relatively small difference to the overall avoided cost of energy.

5.7 ACHIEVABLE POTENTIAL

As noted previously, Achievable Potential was assessed from two perspectives:

- Potential Savings in Future Natural Gas Consumption Savings in one year due to the Aggregate impact of measures implemented over the time period of Base Year (2007) to Milestone Year (2012 and 2017). This method calculates the net change in future natural gas supply requirements.

- Potential DSM Program TRC Benefits. [27] Savings due to (only) those measures implemented in one year. This method is used in calculation of the net TRC benefits.

Within each of the above perspectives, the analysis of Achievable Potential was assessed under four different Marketing scenarios:

- One Financially Unconstrained scenario
- Three Financially Constrained scenarios, each limited by a different level of program budget availability.

Further detail related to each of the Marketing scenarios is provided below followed by a summary of results.

5.7.1 Financially Unconstrained DSM Marketing Scenario

The Financially Unconstrained scenario provides an overview of the level of potential natural gas savings that could be achieved if a comprehensive portfolio of DSM programs was launched without any constraint on the availability of program funding.

[27] The annual savings presented do not explicitly address the potential impact of free riders at the level of individual program measure. However, the Reference Case 3 does include an estimate of the impact of natural conservation over the study period, by end use (i.e., an estimate of natural gas savings that would occur in the absence of additional Enbridge DSM programs). Hence, the inclusion of natural conservation in the study's Reference Case does address some, but not necessarily all, free rider and spillover impacts. A more detailed assessment of free rider and spillover impacts is practical only as part of a detailed program design, which is beyond the scope of this study.

Although the results of this scenario are not constrained by program funding, the results do incorporate consideration of the market constraints identified during the Achievable Potential workshop, such as product and service availability and customer transaction costs.

This scenario, therefore, provides a high-level estimate of the upper level of natural gas savings that could be achieved by Enbridge's industrial customers over the nine-year period beginning in 2009 and ending in 2017. It also provides Enbridge's industrial DSM program personnel with a view of the relative potential contribution of individual sub sectors, end uses, technologies and service regions.

Major Assumptions: Financially Unconstrained Scenario

- All measures that pass the measure TRC screen are included
- No program financial limit is set, except that all measures must continue to pass the measure TRC screen
- Participation rates for each measure are based on the workshop results, which consider both market barriers and potential promotional strategies.

Exhibit 5.10 provides details on the program costs assumed for each measure.

Exhibit 5.10: Summary of Program Cost Assumptions, Financially Unconstrained Scenario[28]

End Use	Bundle	Measure Name	Fixed Program Costs ($/yr)	Incentive ($/m^3)	Payback After Incentive (yrs)[29]
System wide	1	Integrated control system	20,000	0.07	0.9
	2	Sub-metering	25,000	0.07	2.8
Boiler	3	Heat recovery to preheat makeup water	20,000	0.07	6.0
		Boiler combustion air preheat	20,000	0.07	9.8
		Minimize deaerator vent losses	20,000	0.07	5.8
		Blowdown heat recovery	20,000	0.07	6.6
		Boiler water treatment	20,000	0.07	4.3
		High efficiency burners	20,000	0.07	3.3
		Advanced boiler controls	20,000	0.07	2.7
		Economizer	20,000	0.07	3.8
		Weighted Average for Bundle 3	160,000		5.2
	4	Boiler right sizing and load management	20,000	0.07	-0.5
	5	Steam trap survey and repair	12,000	0.07	1.6
	6	Condensate return	25,000	0.07	5.9
	7	Insulation	20,000	0.07	1.8
	8	Boiler maintenance	20,000	0.07	2.3
	9	Condensing boiler	27,000	0.07	2.1
		Direct contact hot water heaters	27,000	0.07	-0.1
		Weighted Average for Bundle 9	54,000		0.5
Process	10	Exhaust gas heat recovery	32,500	0.07	4.1
		High efficiency burners	32,500	0.07	1.8
		Insulation	32,500	0.07	1.6
		Advanced heating and process controls	32,500	0.07	4.7
		Weighted Average for Bundle 10	130,000		2.9
	11	High-efficiency ovens	12,500	0.07	0.9
		High-efficiency dryers	12,500	0.07	0.7
		High-efficiency kilns	12,500	0.07	0.0
		High-efficiency furnaces	12,500	0.07	0.3
		Radiant tube burners	12,500	0.07	4.4
		Weighted Average for Bundle 11	62,500		0.3
Other	12	Process Heat Recovery	80,000	0.07	3.5
HVAC	13	Automated temperature control	30,000	0.07	6.4
		Air compressor heat recovery	30,000	0.07	5.4
		Radiant heaters	30,000	0.07	4.8
		Destratification fans	12,000	0.07	5.7
		Weighted Average for Bundle 13	30,000		4.6
	14	Ventilation Optimization	15,000	0.07	4.4
		Ventilation Heat Recovery	15,000	0.07	4.7
		Weighted Average for Bundle 14	30,000		4.6

[28] Salary and related overhead costs are not included in program cost estimates.

[29] The payback period is a weighted average payback period for the measures based on technology size distribution and gas consumption by sub sector.

5.7.2 Financially Constrained DSM Marketing Scenarios

These DSM Marketing scenarios provide estimates of the potential impacts of increasingly larger annual DSM budgets, which as noted previously were set at $20, $40 and $60 million, annually. Within each of these budgets, 20% of the funding is allocated to the Industrial sector for the purposes of this analysis.

The financially constrained scenarios include the following DSM costs:

- **Fixed Program Costs**: This includes costs for items such as newspaper advertisements, preparation of information and marketing materials, training workshops, contractor certifications, etc. These program cost elements are not expected to vary significantly if the number of installations of the measure changed. Estimates for these cost items were provided by Enbridge personnel, based on current and previous experience with similar DSM measures. In each case, these costs are expressed as dollars of program spending per year. For each of the measures, fixed program costs were estimated for both the CML and Financially Unconstrained Marketing scenarios. Salary and related overhead costs are not included.

- **Incentive Costs** (either end user or channel member): These costs would include any costs that vary directly according to the volume of gas saved by the measure. An incentive of $ 0.05 / m^3 gas saved was used for the CML scenario and $ 0.07 / m^3 gas saved for the Financially Unconstrained scenario. For each of the measures, incentive costs were estimated for both the CML and the Financially Unconstrained scenarios based on the volume of gas saved.

Exhibit 5.11 provides details on the program costs assumed for each measure.

Exhibit 5.11: Summary of Program Cost Assumptions, CML Scenario[30]

End Use	Bundle	Measure Name	Fixed Program Costs ($/yr)	Incentive ($/m^3)	Payback After Incentive (yrs)[31]
System wide	1	Integrated control system	15,000	0.05	0.9
	2	Sub-metering	10,000	0.05	2.9
Boiler	3	Heat recovery to preheat makeup water	15,000	0.05	6.2
		Boiler combustion air preheat	15,000	0.05	10.0
		Minimize deaerator vent losses	15,000	0.05	5.9
		Blowdown heat recovery	15,000	0.05	6.8
		Boiler water treatment	15,000	0.05	4.4
		High efficiency burners	15,000	0.05	3.4
		Advanced boiler controls	15,000	0.05	2.7
		Economizer	15,000	0.05	3.9
		Weighted Average for Bundle 3	120,000		5.3
	4	Boiler right sizing and load management	15,000	0.05	-0.5
	5	Steam trap survey and repair	8,000	0.05	1.6
	6	Condensate return	10,000	0.05	6.0
	7	Insulation	15,000	0.05	1.8
	8	Boiler maintenance	15,000	0.05	2.3
	9	Condensing boiler	8,000	0.05	2.1
		Direct contact hot water heaters	8,000	0.05	-0.1
		Weighted Average for Bundle 9	16,000		0.5
Process	10	Exhaust gas heat recovery	2,500	0.05	4.2
		High efficiency burners	2,500	0.05	1.9
		Insulation	2,500	0.05	1.6
		Advanced heating and process controls	2,500	0.05	4.9
		Weighted Average for Bundle 10	10,000		2.9
	11	High-efficiency ovens	2,500	0.05	0.9
		High-efficiency dryers	2,500	0.05	0.7
		High-efficiency kilns	2,500	0.05	0.0
		High-efficiency furnaces	2,500	0.05	0.3
		Radiant tube burners	2,500	0.05	4.4
		Weighted Average for Bundle 11	12,500		0.7
Other	12	Process Heat Recovery	2,000	0.05	3.6
HVAC	13	Automated temperature control	5,000	0.05	6.5
		Air compressor heat recovery	5,000	0.05	5.5
		Radiant heaters	5,000	0.05	4.9
		Destratification fans	10,000	0.05	5.8
		Weighted Average for Bundle 13	25,000		5.3
	14	Ventilation Optimization	10,000	0.05	4.5
		Ventilation Heat Recovery	10,000	0.05	4.8
		Weighted Average for Bundle 14	20,000		4.7

[30] Salary and related overhead costs are not included in program cost estimates.

[31] The payback period is a weighted average payback period for the measures based on technology size distribution and gas consumption by sub sector.

5.7.3 Achievable Potential Savings - Future Natural Gas Consumption[32]

Exhibits 5.12 to 5.14, inclusive, present a summary of the Achievable Potential savings in future natural gas consumption relative to the Reference Case levels. For illustration, the results of the Financially Unconstrained scenario are shown.

Selected highlights are provided below.

- Exhibit 5.12 shows that total industrial sector natural gas savings in 2017 are estimated to be approximately 392 million m^3/yr. This represents a savings of approximately 15%, relative to the Reference Case and is equal to approximately 43% of the savings identified in the Economic Potential Forecast. The Central service region accounts for about 87% of the identified potential.

- Exhibit 5.13 shows the results by sub sector for the entire Enbridge service area. As illustrated, the majority of savings in the unconstrained scenario are associated with the Miscellaneous Manufacturing sub-sector (39%), while the Food Product Manufacturing and Paper Manufacturing sub sectors each contribute approximately 12% each.

- Exhibit 5.14 shows the results by end use. As illustrated, measures applied to three end-uses, boiler steam systems, HVAC, and process heat, account for approximately 93% of the identified potential. Additional details describing the specific measures that contribute to these end-use savings are provided in the following sections.

Exhibit 5.12: Natural Gas Savings by Service Region and Milestone Year, Financially Unconstrained Scenario (1000 m^3/yr.)

Milestone Year	Eastern Region	Central Region	Total	% Savings Relative to Ref Case
	thousand m^3/year			
2012	21,055	149,446	170,501	7%
2017	49,817	342,337	392,155	15%
% Savings 2017 Re: Reference Case	15%	15%	15%	
% Savings 2017 Re: Total	13%	87%	100%	

[32] See definition of savings as provided in Step 6, page 7.

Exhibit 5.13: Natural Gas Savings by Sub-Sector and Milestone Year for the Total Enbridge Service Area, Financially Unconstrained Scenario (1000 m^3/yr.)

Sub-Sector	Milestone Year		% Savings 2017	
	2012	2017	Re: Ref Case	Re: Total
	thousand m^3/year			
Non-metallic Mineral Product Mfg.	13,519	30,297	11%	8%
Food Product Mfg.	22,347	48,545	14%	12%
Paper Manufacturing	20,618	46,080	15%	12%
Refined Petroleum & Coal	16,873	37,382	12%	10%
Primary Metal	9,966	22,686	11%	6%
Fabricated Metal	11,473	27,278	14%	7%
Chemical	11,654	26,289	14%	7%
Miscellaneous Mfg.	64,051	153,598	17%	39%
Total	170,501	392,155	15%	100%

Exhibit 5.14: Natural Gas Savings by End Use and Milestone Year for the Total Enbridge Service Area, Financially Unconstrained Scenario (1000 m^3/yr.)

Sub-Sector	Milestone Year		% Savings 2017	
	2012	2017	Re: Ref Case	Re: Total
	thousand m^3/year			
Systems	2,062	13,331	0.5%	3%
Hot Water Systems	4,851	9,829	11%	3%
Boiler Steam Systems	60,858	121,470	15%	31%
Process Heat	40,989	81,921	8%	20%
Other Process	2,354	4,765	4%	1%
HVAC	59,388	160,839	27%	41%
Total	170,501	392,155	15%	100%

6.7.4 Potential DSM Program TRC Benefits

Exhibits 5.15, 5.16 and 5.17, present the results for the milestone year 2017. As illustrated, annual industrial program spending of approximately $4.4 million in 2017 would result in approximately 48 million m^3/year in natural gas savings[33] and approximately $44 million in TRC net benefits. The exhibits also illustrate that annual Industrial sector program spending achieves maximum results at an annual expenditure of $3.1 million in 2012, which is below the $4 million industrial budget, and $4.4 million in 2017, which is below the $8 million industrial budget. This is because additional cost-effective measures were not available under the conditions defined by these scenarios. Additional details are provided in the following exhibits.

33 Note: the savings shown are only for the measures installed in 2017; they do not include the savings in 2017 that occur as a result of measures installed in prior periods.

- Exhibit 5.15 presents the 2017 results by upgrade technology bundle, including both the current marketing level of participation and the increment from current marketing level to Financially Unconstrained. For each measure bundle, annual natural gas savings potential, net TRC benefits, and annual program costs are presented both individually and cumulatively. The measures are sorted in order of increasing program cost per dollar of TRC benefits.

- Exhibit 5.16 presents the 2017 results graphically, with program costs on the vertical axis and net TRC benefits on the horizontal axis.

- Exhibit 5.17 presents the 2017 results graphically, with program costs on the vertical axis and annual natural gas savings potential on the horizontal axis.

Exhibit 5.15: Summary Achievable Results** by Measure, for the Total Enbridge Service Area, 2017 Installations

Measure Bundle	Scenario	Annual Natural Gas Savings Potential (1000 m^3/yr)		TRC ($)		Annual Program Costs ($)		Program Costs per Unit	
			Cumulative		Cumulative		Cumulative	per Natural Gas Savings ($/$m^3$)	per TRC Benefits ($/$)
10	CML	2,668	2,668	4,618,451	4,618,451	143,384	143,384	0.05	0.03
1	CML	2,446	5,114	4,125,519	8,743,969	137,325	280,709	0.06	0.03
9	CML	83	5,197	490,517	9,234,486	20,135	300,843	0.24	0.04
12	CML	128	5,325	187,460	9,421,947	8,406	309,249	0.07	0.04
2	CML	719	6,044	1,020,872	10,442,819	45,945	355,194	0.06	0.05
4	CML	1,957	8,001	2,114,150	12,556,969	112,857	468,051	0.06	0.05
9	Unconstrained	221	8,222	1,297,911	13,854,880	71,104	539,155	0.32	0.05
2	Unconstrained	3,145	11,367	4,485,051	18,339,931	259,539	798,694	0.08	0.06
10	Unconstrained	5,704	17,071	9,766,933	28,106,864	582,651	1,381,344	0.10	0.06
4	Unconstrained	2,540	19,611	2,743,063	30,849,926	236,932	1,618,277	0.09	0.09
1	Unconstrained	864	20,475	1,441,935	32,291,862	129,397	1,747,673	0.15	0.09
14	CML	3,620	24,094	1,804,404	34,096,266	200,983	1,948,657	0.06	0.11
7	CML	836	24,931	398,624	34,494,890	56,804	2,005,461	0.07	0.14
6	CML	199	25,130	130,800	34,625,690	19,958	2,025,419	0.10	0.15
3	CML	4,040	29,170	2,049,997	36,675,687	322,009	2,347,427	0.08	0.16
14	Unconstrained	7,252	36,422	3,625,066	40,300,753	610,016	2,957,443	0.08	0.17
12	Unconstrained	435	36,856	562,594	40,863,347	112,978	3,070,421	0.26	0.20
7	Unconstrained	952	37,808	450,738	41,314,085	103,328	3,173,750	0.11	0.23
13	Unconstrained	1,509	39,316	551,741	41,865,826	143,295	3,317,044	0.09	0.26
6	Unconstrained	302	39,619	188,824	42,054,650	50,154	3,367,198	0.17	0.27
3	Unconstrained	3,635	43,254	1,792,452	43,847,103	495,264	3,862,462	0.14	0.28
11	CML	360	43,614	50,063	43,897,166	30,486	3,892,948	0.08	0.61
8	CML	295	43,909	43,751	43,940,916	29,775	3,922,723	0.10	0.68
13	CML	634	44,544	140,538	44,081,454	133,722	4,056,445	0.21	0.95
8	Unconstrained	307	44,851	41,068	44,122,522	47,411	4,103,856	0.15	1.15
11	Unconstrained	938	45,788	100,593	44,223,116	135,337	4,239,193	0.14	1.35
5	CML	941	46,730	13,048	44,236,164	55,073	4,294,266	0.06	4.22
5	Unconstrained	1,308	48,038	17,243	44,253,407	122,390	4,416,656	0.09	7.10
				Weighted Average (@ $4M Industrial spending):				0.09	0.09
				Weighted Average (total):				0.09	0.10

** Savings shown are incremental to those for preceding measures.

Exhibit 5.16: Achievable Potential Supply Curve, 2017: Program Cost vs. TRC Net Benefits, for the Total Enbridge Service Area

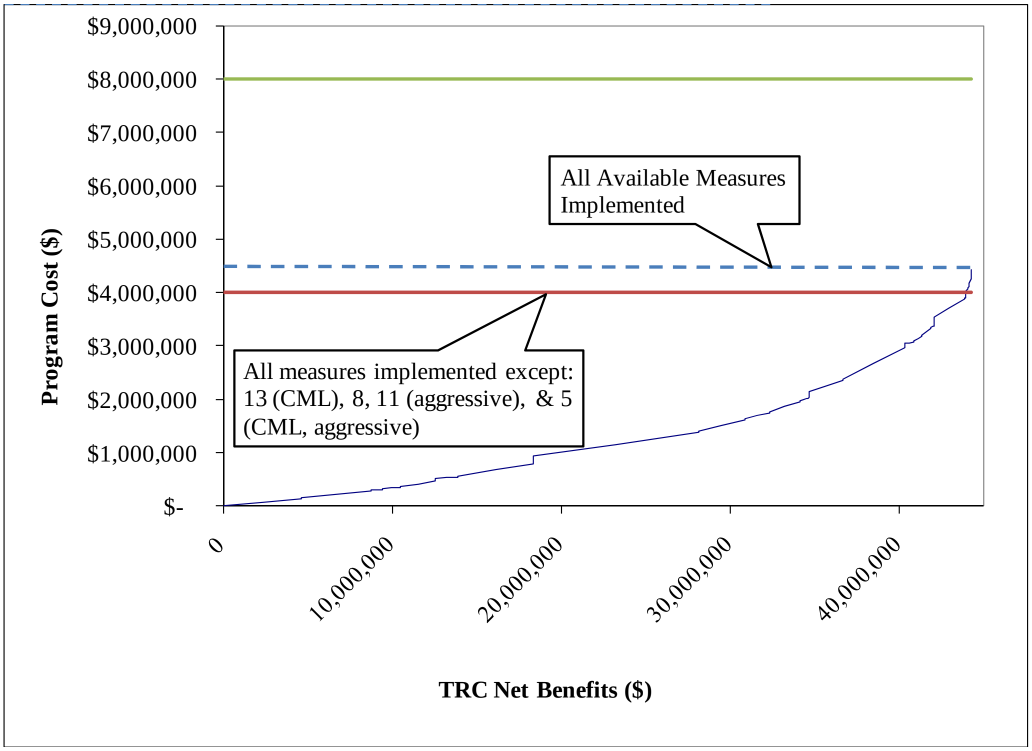
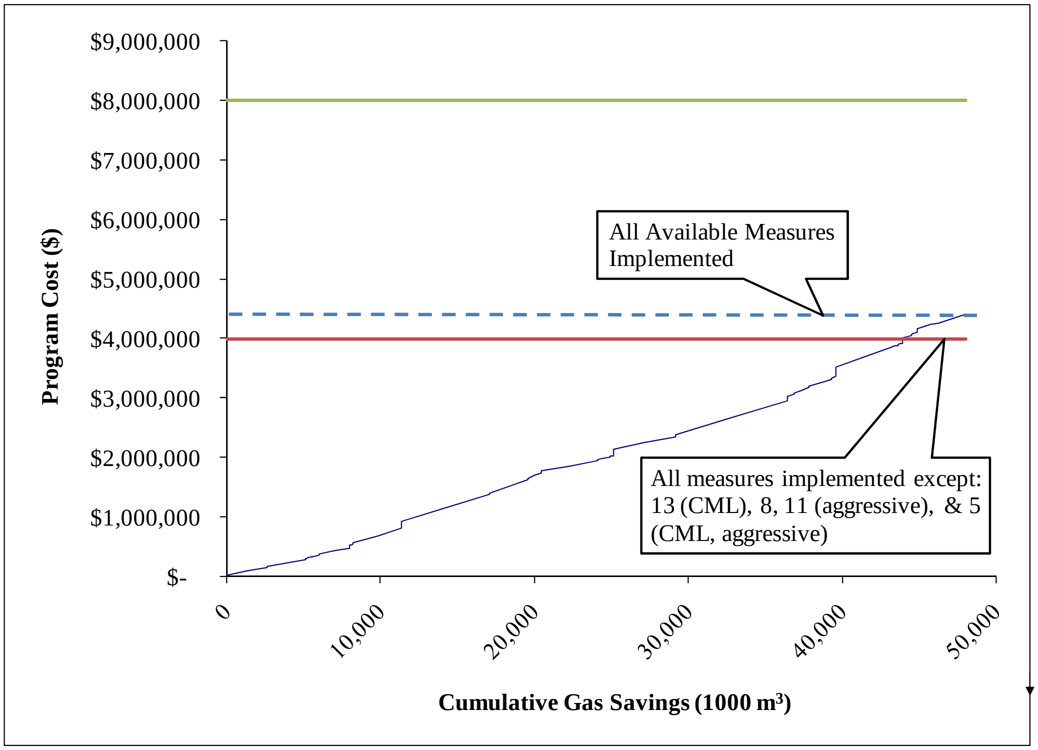


Exhibit 5.17: Achievable Potential Supply Curve, 2017: Program Cost vs. Annual Natural Gas Savings Potential, for the Total Enbridge Service Area



5.7.5 Conclusions

Selected highlights are provided below.

- Annual Industrial sector program spending achieves maximum results at an annual expenditure of $3.1 million in 2012, which is below the $4 million industrial budget, and $4.4 million in 2017, which is below the $8 million industrial budget. This is because additional cost-effective measures were not available under the conditions defined by these scenarios.

- With industrial program spending of approximately $4.4 million in 2017, program costs are approximately $0.09 per gross m^3 of natural gas savings and $0.09 per dollar of gross TRC benefits. This compares with recent Enbridge monitoring and evaluation results[34] of $0.06/m^3 of gross natural gas savings ($0.07/m^3 net of free riders).

- Program costs per dollar of TRC net benefits are particularly attractive for the following measure bundles:
  - Bundle 10 – Retrofitting ovens, dryers, kilns and furnaces to improve efficiency, such as exhaust gas heat recovery, high efficiency burners, insulation and advanced heating and process controls
  - Bundle 1 – System wide integrated control systems
  - Bundle 9 – Upgrading to more efficient boilers and heaters, such as condensing boilers and direct contact hot water heaters
  - Bundle 12 – Process heat recovery
  - Bundle 2 – System wide sub-metering
  - Bundle 4 – Boiler right sizing and load management

5.8 ADDITIONAL OBSERVATIONS

In addition to the preceding conclusions, two additional observations warrant note as they may affect future Industrial sector program strategies. They include:

- ***Rate of measure implementation has a large effect on overall savings:*** For measures that pass the TRC screen on an incremental cost basis, low participation rates in early milestone years create a significant “lost opportunity.” This is particularly relevant to the replacement of equipment with a very long life, which is applicable to most industrial technologies and measures. The gap between Economic Potential and Achievable Potential savings presented in this study is due in large part to the significant lost opportunity that occurs in early milestone years.

- ***Bundling of measures to develop program concepts has an impact on the achievable potential and program development:*** To model the achievable potential scenario measures were grouped into bundles that are manageable within the scope and budget of the project. The Achievable results provide an indicative savings potential based on the

[34] Enbridge Gas, 2007 LRAM Post Audit Results.

specific set of bundles. Savings from individual measures, or different bundle mixes of measures, will vary.

GLOSSARY

achievable potential
The Achievable Potential is the proportion of the natural gas savings identified in the Economic Potential Forecast that could realistically be achieved within the study period. Achievable Potential recognizes that it is difficult to induce customers to purchase and install all of the efficiency technologies that meet the criteria defined by the Economic Potential Forecast.

avoided cost
The unit cost of acquiring the next resource to meet demand, which is used as a measure for evaluating individual demand-side and supply-side options. In the context of this study "avoided cost" is the capital expenditure offset by Enbridge's DSM activities (i.e., the cost of having to buy natural gas on the open market, contract for long-term supply, and the cost of associated transmission and storage.

base year
The Base Year is the year to which all potentials will be compared. It provides a detailed description of "where" and "how" natural gas is currently used in each sector. For this study, it is the calendar year 2007. The modelled base year energy use is calibrated against Enbridge's actual sales for 2007.

benefit/cost ratio
The measure benefit/cost ratio indicates the relative attractiveness of the measures. A measure that has a benefit/cost ratio in excess of 1.0 has benefits which outweigh its costs. Similarly, a measure with a benefit/cost ratio that is well in excess of one (e.g., 3.0) means that it is very attractive. A measure with a benefit/cost ratio of less than 1.0 has costs which outweigh its benefits.

building envelope
The material separation between the interior and the exterior environments of a building. The building envelope serves as the outer shell to protect the indoor environment as well as to facilitate its climate control.

british thermal unit or BTU
The standard measure of heat energy. It takes one Btu to raise the temperature of one pound of water by one degree Fahrenheit at sea level

co-generation
The simultaneous production of electric or mechanical energy and useful heat energy from a single fuel source.

combustion efficiency
The ratio of energy released during combustion to the potential chemical energy available in the fuel.

demand-side management (DSM)
Actions taken by a utility or other agency which are expected to influence the amount or timing of a customers energy consumption.

discount rate
The interest rate used in calculating the present value of expected yearly benefits and costs.

economic efficiency
Allocation of human and natural resources in a way that results in the greatest net economic benefit, regardless of how benefits and costs are distributed within society.

economic potential forecast
The economic potential forecast is an estimate of the level of natural gas consumption that would occur if all equipment and building envelopes were upgraded to the level that is cost effective from society's perspective. All of the energy-efficiency technologies and measures that have a positive measure TRC are incorporated into the economic potential forecast. These technologies and measures are applied at either natural stock turnover rates or at designated years for immediate application.

energy audit
An on-site inspection and cataloguing of energy using equipment/buildings, energy consumption and the related end-uses. The purpose is to provide information to the customer and the utility. Audits are useful for load research, for DSM program design and for identification of specific energy savings measures.

energy conservation
Activities by energy users that result in a reduction of the energy used to provide services. Energy conservation can include a wide variety of behavioural or operational changes that result in energy savings..

Energy efficiency
Using less energy to perform the same function. For the purpose of this study, only energy savings achieved through physical or hardware installations are considered.

energy intensity
The ratio of energy consumed per application or end use. For example, cubic metres per square metre of heated office space per day, or cubic metres per tonne of aluminum produced. All else being equal, energy intensity increases as energy efficiency decreases.

emerging technologies
New energy-conserving technologies that are not yet market-ready, but may be market-ready over next 5 to 10 years. This category includes technologies that could be accelerated into the market during that period through targeted financial or technical support.

end use
The final application or final use to which energy is applied. End use is often used interchangeably with energy service.

energy savings
The reduction in use of energy from the pre retrofit baseline to the post retrofit energy use that result from efficient technologies or activities. In this document, the term "energy" refers specifically to energy derived from natural gas unless otherwise noted.

energy service
An amenity or service supplied jointly by energy and other components/equipment such as buildings and heating equipment. Examples of energy services include residential space heating, commercial cooking, aluminum smelting and public transit. The same energy service can frequently be supplied with different mixes of equipment and energy.

energy use index (EUI)
End use energy consumption divided by a specific parameter of production (e.g., m^3/unit)
environmental credit/environmental penalty
An increment or decrement to the cost of a resource or set of resources, to reflect the overall level of its/their environmental impact, relative to another resource or set of resources.

financial incentive
Certain financial features in the utility's DSM programs designed to motivate customer participation. They may include features designed to reduce a customer's net cash outlay, pay-back period or cost of finance to participate.

fuel share
The proportion of requirements for a specific service that is met using a certain fuel. In the Commercial sector, fuel shares are normalized on a floor area basis. For example, a natural gas fuel share of 90% for space heating in the Large Office sub sector implies that 90% of the sub sector floor space is heated using natural gas.

free rider
A program participant who would have implemented the program measure or practice in the absence of the program.

interactive effects
In the context of natural gas use, interactive effects refer to the increase in gas consumed by heating equipment required to offset a decrease in "waste" heat generated by more efficient electrical fixtures or appliances after retrofit or replacement.

kilowatt (kW)
One thousand watts; the most common unit of measurement of electric power. (The amount of energy transferred at a rate of one kilowatt for one hour is equal to one kilowatt hour.)

kilowatt hour (kWh)
The most common unit of measurement of electric energy. One kilowatt hour represents the power of one thousand watts for a period of one hour.

load forecast
An estimate of expected natural gas requirements that have to be met by the utility in future years.

load research
Research to disaggregate and analyze patterns of natural gas consumption by various subsectors and end-uses. Load Research supports the development of the load forecast and the design of demand-side management programs.

market transformation
A reduction in market barriers resulting from a market intervention, as evident by a set of market effects that lasts after the intervention has been withdrawn, reduced or changed.

measure total resource cost (TRC)
The Measure TRC is the net present value of energy savings that result from an investment in a energy efficiency measure. The Measure TRC is equal to its full or incremental capital cost (depending on application) plus any change (positive or negative) in the combined annual energy and operating & maintenance costs. This calculation includes among others, the following inputs: the avoided natural gas, electricity and water; the life of the measure; and the selected discount rate.

natural conservation
The future change in energy intensity or base usage that is expected to occur in the absence of utility DSM programs. Natural change represents the effects of energy related decisions that would have been made in the absence of the utility programs by both program participants and non-participants

Non-participant:
Any customer who was eligible but did not participate in the utility program under consideration in a given program year.

non-participant test (NPT)
A test measuring what happens to rates due to changes in utility revenues and operating costs caused by a program. Rates will go down if the avoided cost is greater than the sum of the revenue lost plus the program costs. This test indicates the direction and magnitude of the expected change in rate levels.

participant
An individual, household, business or other utility customer that received a service or financial assistance orffered through a particular utility program, set of utility programs or particular aspect of a utility program in a given program year.

rate
Generically refers to a utility's rate structure.

rate structure
The formulae used by a regulated gas utility to calculate charges for the use of natural gas..

rebates
A type of incentive provided to encourage the adoption of energy efficeing practices, typically paid after the measure has been installed. There are typically two types of rebates: a Prescriptive Rebate, which is a prescribed financial incentive/unit for a prescribed list of products and a

customized rebate in which the financial incentive is determined using an analysis of the customer equipment and an agreement on the specific products to be installed.

reference case forecast
An estimate of the expected level of natural gas consumption that would occur over the study period in the absence of any new utility DSM market interventions after 2008. It is the baseline against which the scenarios of energy savings are calculated. The Reference Case forecast incorporates an estimation of “natural conservation,” namely, changes in end-use efficiency over the study period that are projected to occur in the absence of new market interventions by the utility.

retrofit
Energy efficiency activities undertaken in existing residential or non residential buildings where existing inefficient equipment is replaced by efficient equipment.

saturation
The portion of floor area that receives a specific energy service. For example, a saturation of 86% for space cooling in the Large Office sub sector means that 86% of the sub sector floor space is cooled (regardless of fuel used to provide that cooling).

seasonal efficiency
The ratio of delivered useful energy relative to the input potential fuel energy determined over a full heating season (or year).

sector
A group of customers having a common type of economic activity. Enbridge Gas divides its customers into three principal sectors: Residential, Commercial and Industrial. Sectors are further divided into subsectors. For example, “Large Offices” is a sub sector of the Commercial sector.

service area
The portion of the Province of Ontario that receives service from Enbridge Gas.

service region
For the purposes of this study, the total Enbridge Gas service area is divided into two service regions. They are the Southern Region and the Eastern Region.

simple payback
The simple payback is generated to show the customer’s financial perspective. Simple payback is a measure of the length of time required for the cumulative savings from a project to recover its initial investment cost, without taking into account the time value of money

strategic load growth
Utility action to increase (annual) total natural gas demand for specific end uses.

sub sectors
A classification of customers within a sector by common features. Residential subsectors are by type of home (SFD, duplex, apartment, etc.). Commercial subsectors are generally by type of

commercial service (office, retail, warehouse, etc.). Industrial subsectors are by product type (pulp and paper, solid wood products, chemicals, etc.).

supply curves
A curve illustrating the amount of energy (e.g., m^3) or societal benefit available at an appropriate screened price in ascending order of cost.

Total Resource Cost (TRC) Test
A test that compares the total costs of energy efficiency investments, including natural gas conservation programs, to the social cost of natural gas. Un-priced environmental and social costs may be accounted for by changing the cost of either the investment under consideration or the total cost of natural gas in such a way that relative un-priced impacts are reflected. It is used in designing and evaluating programs that are developed from the Energy Efficiency Potential study's results.

utility cost
The total financial cost incurred by the utility to acquire energy resources. For DSM, the costs include all utility program costs, including incentive costs.

watt
The basic unit of measurement of power, at a point in time as capacity or demand.

Ontario Energy Board

2013 Yearbook of Natural Gas Distributors

Published on August 14, 2014

Background on Statistical Yearbook of Natural Gas Distributors

The Ontario Energy Board (the "Board") is the regulator of Ontario's natural gas and electricity sectors. In the natural gas sector, the Board reviews and approves rates proposed to be charged to customers by regulated natural gas distributors.* The Board licenses all marketers who sell natural gas to residential and small commercial customers.

The Board provides this Yearbook of Natural Gas Distributors to publish the financial and operational information collected from regulated natural gas distributors. It is compiled from data submitted by the distributors through the Board's Reporting and Record-Keeping Requirements. This Yearbook is also available electronically on the Board's website.

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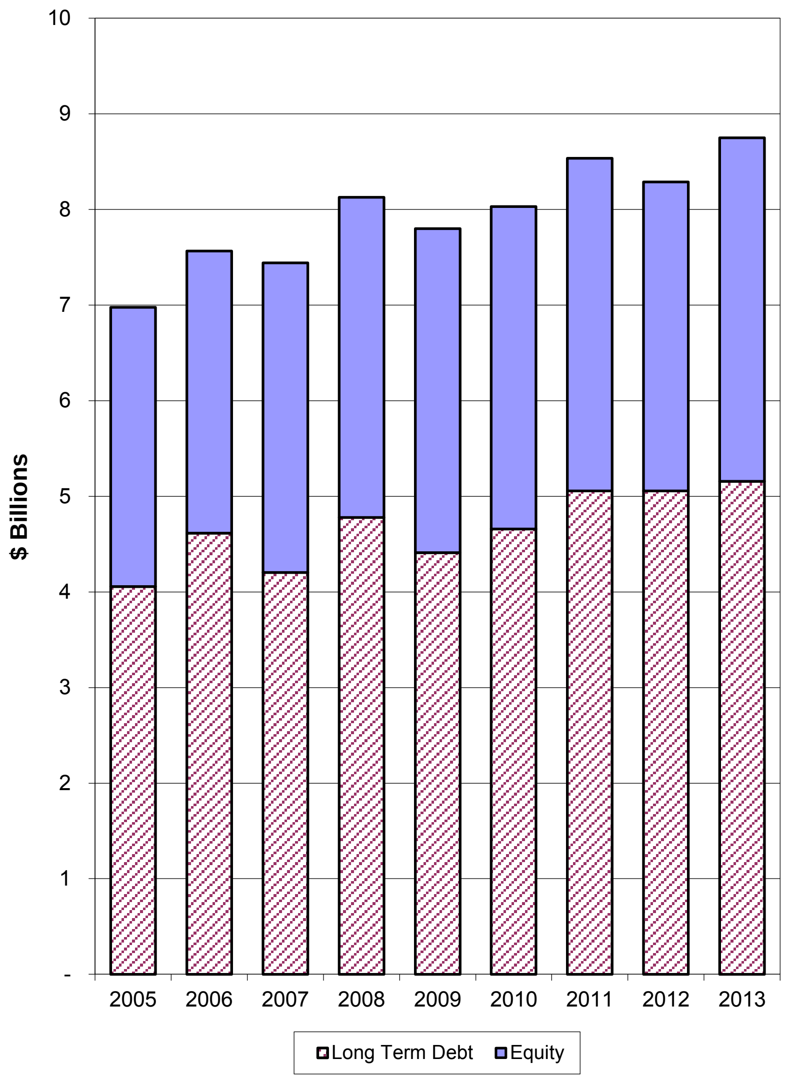
*There are five small gas companies that are exempt from rate regulation under the OEB Act, as well as two municipally owned gas companies (City of Kitchener and City of Kingston) that are not rate regulated by the Board.

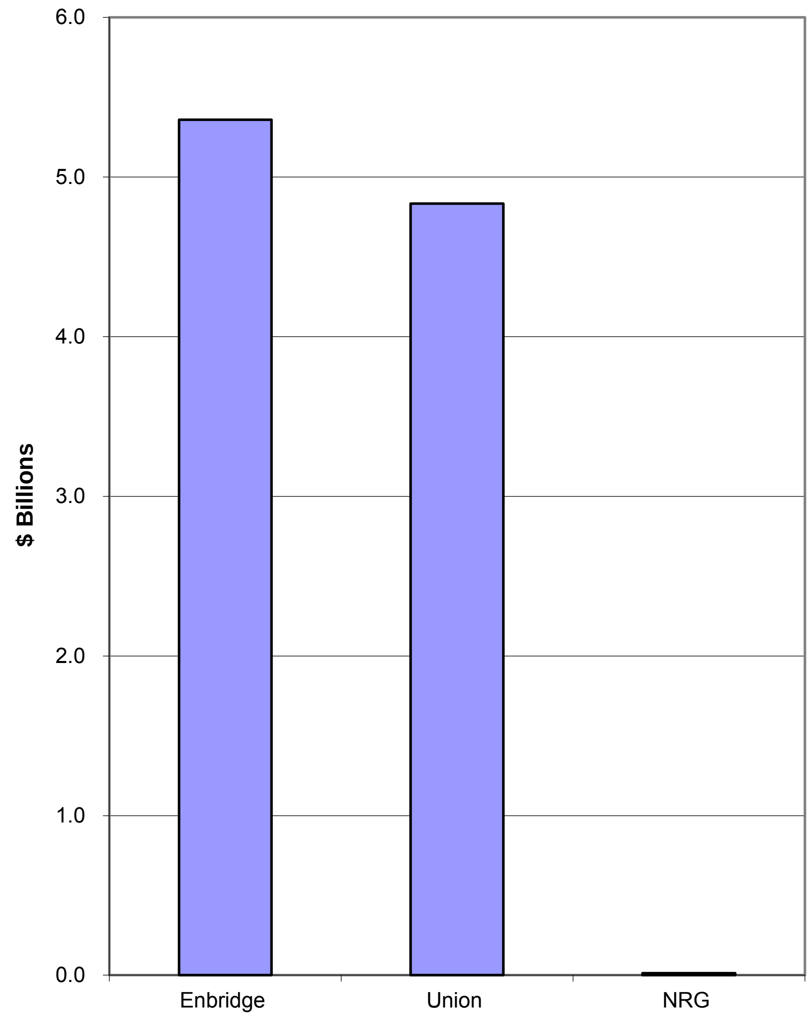
BALANCE SHEET

	ENBRIDGE	UNION	NRG	TOTAL
ASSETS				
Current Assets				
Cash	$ 1,219,244	$ -	$ 1,298,408	$ 2,517,652
Accounts Receivable	582,572,161	807,533,037	845,205	1,390,950,403
Gas Inventories	379,917,493	141,604,217	-	521,521,710
Other Current Assets	66,140,986	34,264,543	94,108	100,499,637
Total Current Assets	**1,029,849,884**	**983,401,797**	**2,237,721**	**2,015,489,402**
Non-Current Assets				
Property, Plant & Equipment	5,358,835,596	4,834,495,155	12,901,555	10,206,232,306
Long-Term Investments	843,495,686	38,986,290	-	882,481,976
Deferred Charges	76,173,482	341,173,979	-	417,347,461
Other Non-Current Assets	276,050,527	8,832,535	689,536	285,572,598
Total Non-Current Assets	**6,554,555,291**	**5,223,487,959**	**13,591,091**	**11,791,634,341**
TOTAL ASSETS	**$ 7,584,405,175**	**$ 6,206,889,756**	**$ 15,828,812**	**$ 13,807,123,743**
LIABILITIES & SHAREHOLDERS' EQUITY				
Current Liabilities				
Bank Overdraft, Loans and Notes Payable	369,781,291	326,431,833	-	696,213,124
Accounts Payable & Accrued Liabilities	529,463,924	746,880,223	1,828,755	1,278,172,902
Other Current Liabilities	78,259,762	49,526,824	1,099	127,787,685
Income Taxes Payable	10,373,140	8,592,760	189,949	19,155,849
Current Portion of Long-Term Debt	400,000,000	150,000,000	-	550,000,000
Total Current Liabilities	**1,387,878,117**	**1,281,431,640**	**2,019,803**	**2,671,329,560**
Non-Current Liabilities				
Long-Term Debt	2,755,000,000	2,394,858,600	6,063,799	5,155,922,399
Deferred Income Taxes	-	408,216,338	441,000	408,657,338
Other Non-Current Liabilities	1,256,153,621	721,063,290	646,782	1,977,863,693
Total Non-Current Liabilities	**4,011,153,621**	**3,524,138,229**	**7,151,581**	**7,542,443,431**
TOTAL LIABILITIES	**5,399,031,738**	**4,805,569,868**	**9,171,384**	**10,213,772,990**
SHAREHOLDERS' EQUITY				
Share Capital & Retained Earnings	2,185,373,437	1,401,319,888	6,657,428	3,593,350,753
LIABILITIES & SHAREHOLDERS' EQUITY	**$ 7,584,405,175**	**$ 6,206,889,756**	**$ 15,828,812**	**$ 13,807,123,743**

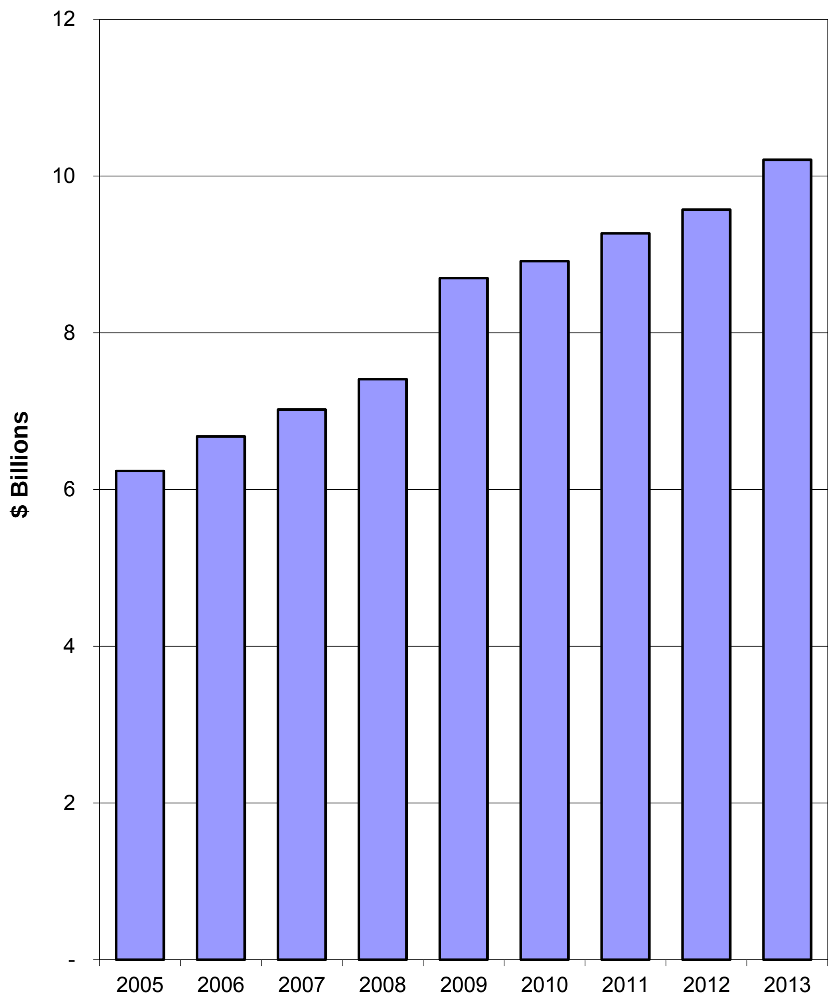
Long-Term Debt & Equity



Net Property and Equipment by Distributor



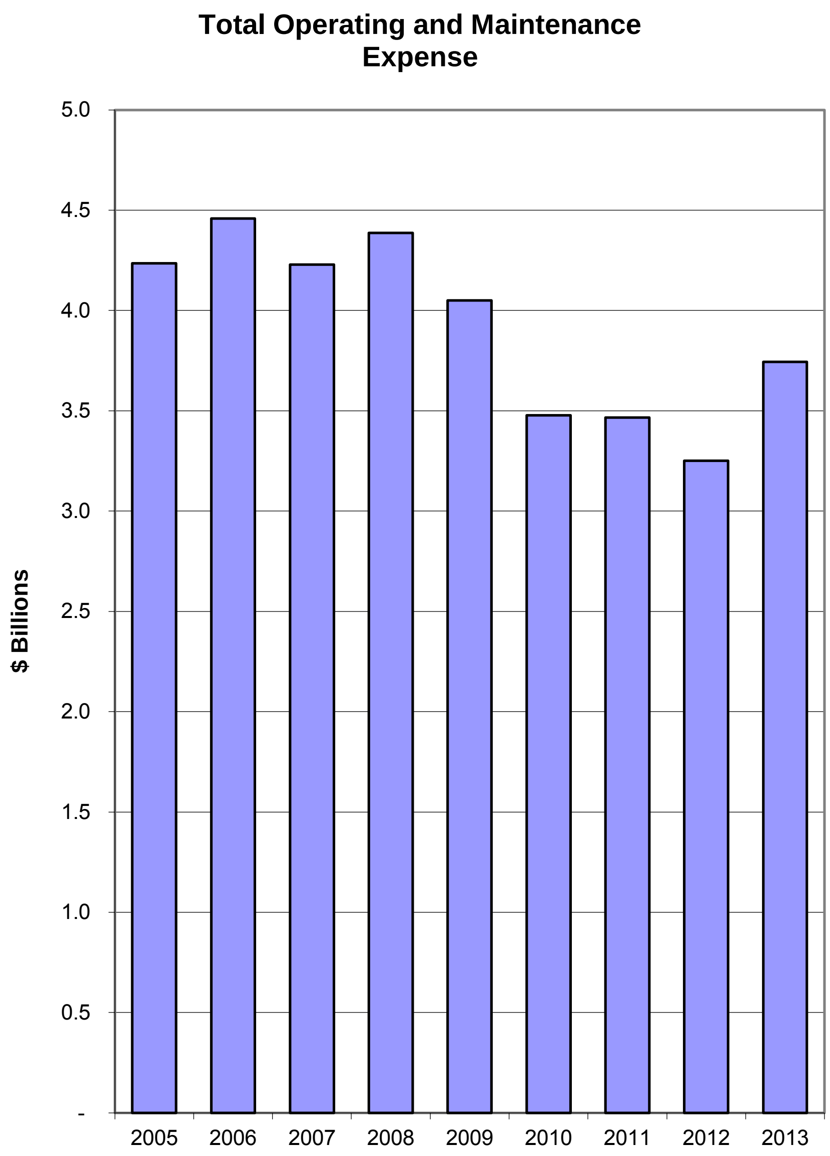
Net Property Plant and Equipment

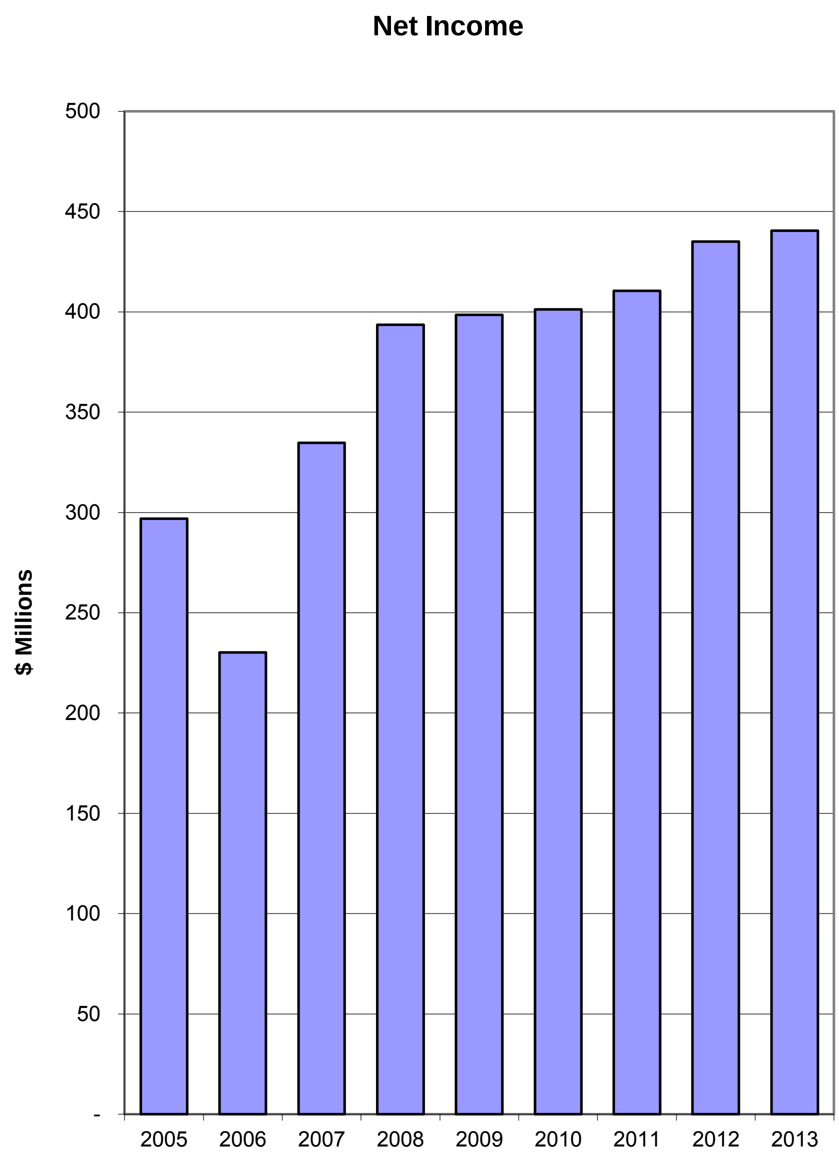


INCOME STATEMENT

	ENBRIDGE	UNION	NRG	TOTAL
Revenues				
Operating Revenues	$ 2,582,918,801	$ 1,872,361,160	$ 10,440,721	$ 4,465,720,681
Other Income	20,875,846	27,041,512	11,522	47,928,880
	2,603,794,647	**1,899,402,672**	**10,452,243**	**4,513,649,561**
Expenses				
Gas Cost, Operating and Maintenance	2,218,590,160	1,515,712,813	10,237,832	3,744,540,805
Interest	174,015,619	155,738,774	211,304	329,965,697
	2,392,605,779	**1,671,451,587**	**10,449,136**	**4,074,506,502**
Net Operating Income	**211,188,868**	**227,951,084**	**3,106**	**439,143,059**
Miscellaneous Income	69,262,479	1,172,040	629,001	71,063,520
Income Before Income Taxes	**280,451,347**	**229,123,125**	**632,107**	**510,206,579**
Income Taxes	48,570,518	21,061,254	169,000	69,800,772
Net Income	**$ 231,880,829**	**$ 208,061,871**	**$ 463,107**	**$ 440,405,807**

Note: Reported results include certain non-utility activities that are not regulated by the Ontario Energy Board.

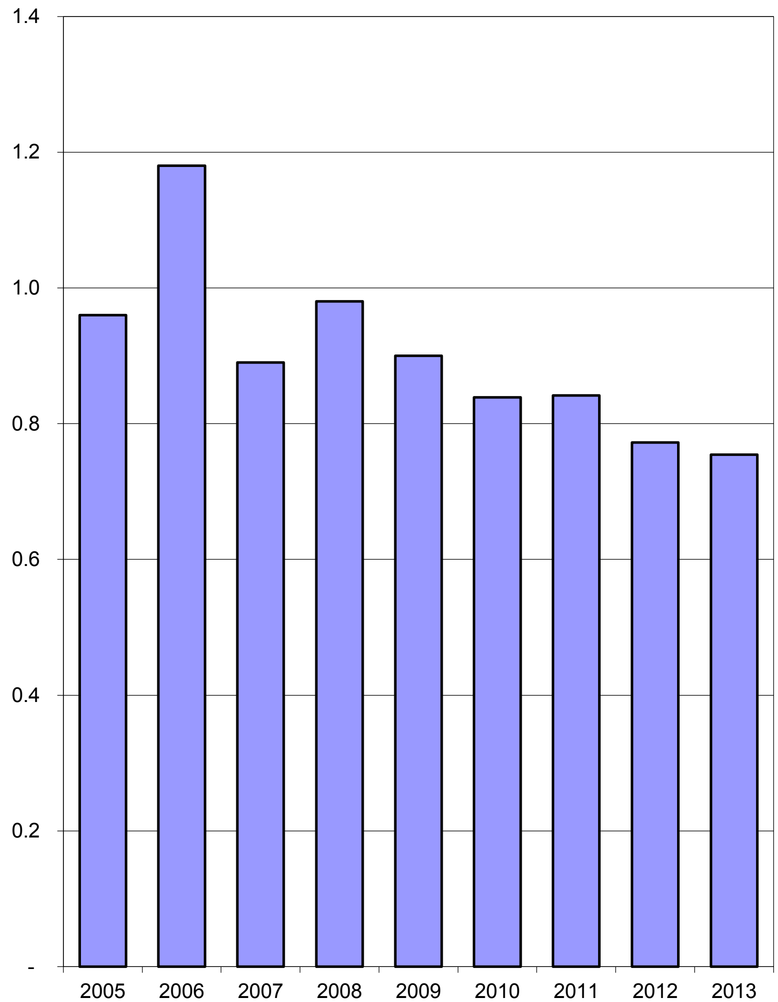

Total Operating and Maintenance Expense
$ Billions
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
-
2005
2006
2007
2008
2009
2010
2011
2012
2013


Net Income
$ Millions
500
450
400
350
300
250
200
150
100
50
-
2005
2006
2007
2008
2009
2010
2011
2012
2013

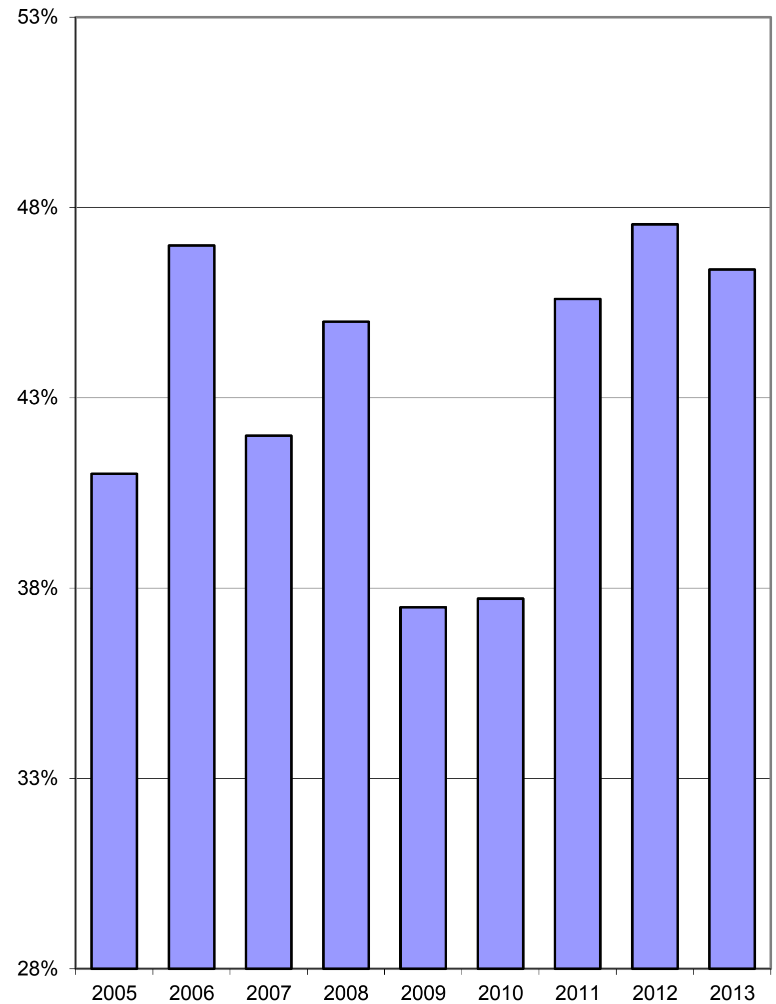
FINANCIAL RATIOS

	ENBRIDGE	UNION	NRG	TOTAL
Liquidity Ratios				
Current Ratio (Current Assets/Current Liabilities)	0.74	0.77	1.11	0.75
Leverage Ratios				
Debt Ratio (Total Debt/Total Assets)	46%	46%	38%	46%
Debt to Equity Ratio (Total Debt/Shareholders' Equity)	1.61	2.05	0.91	1.78
Interest Coverage (EBIT/Interest Charges)	2.61	2.47	3.99	2.55
Profitability Ratios				
Financial Statement Return on Assets (Net Income/Total Assets)	3.06%	3.35%	2.93%	3.19%
Financial Statement Return on Equity (Net Income/Shareholders' Equity)	10.61%	14.85%	6.96%	12.26%

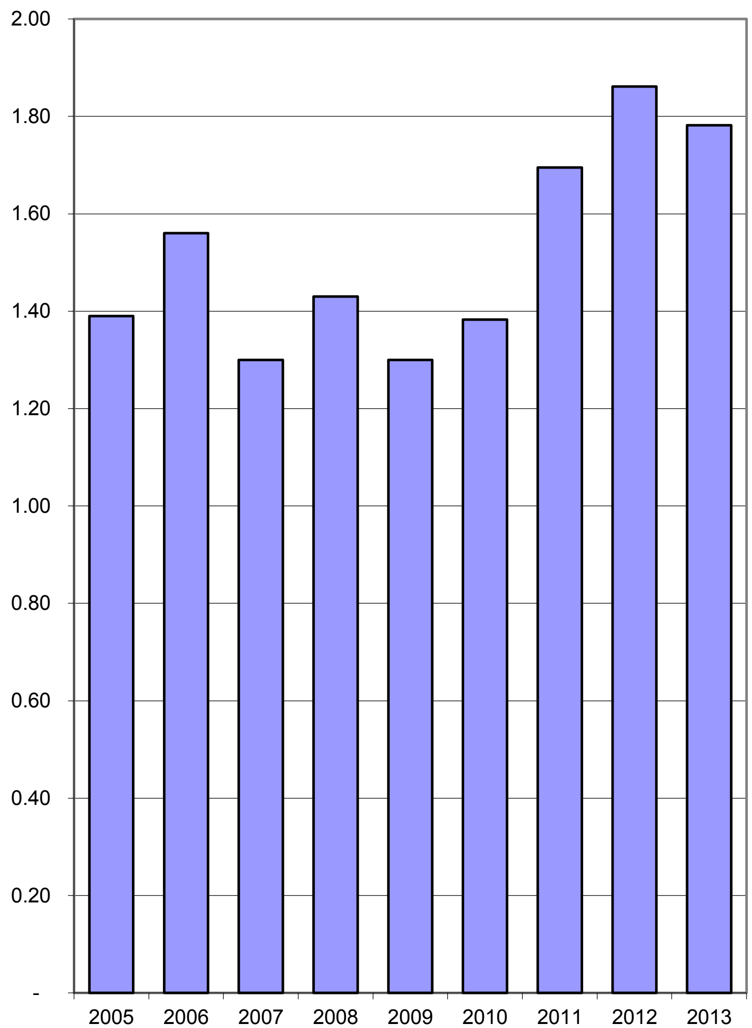
Current Ratio
(Current Assets/Current Liabilities)



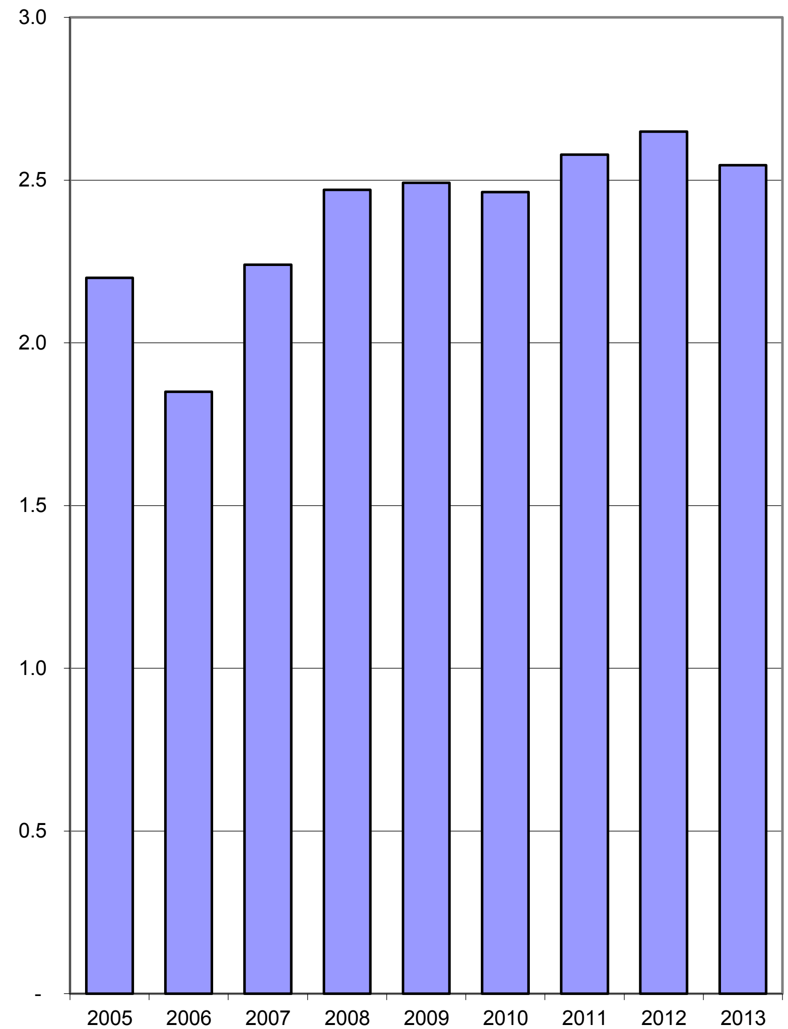
Debt Ratio
(Total Debt/Total Assets)



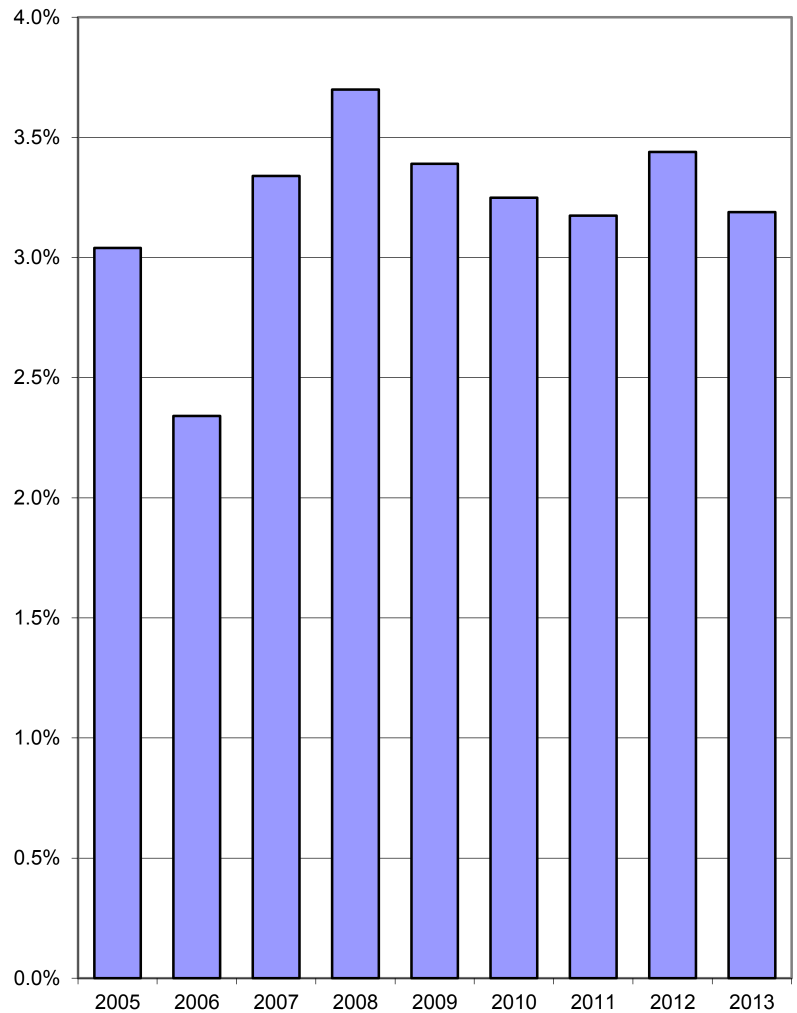
Debt to Equity Ratio
(Total Debt/Equity)



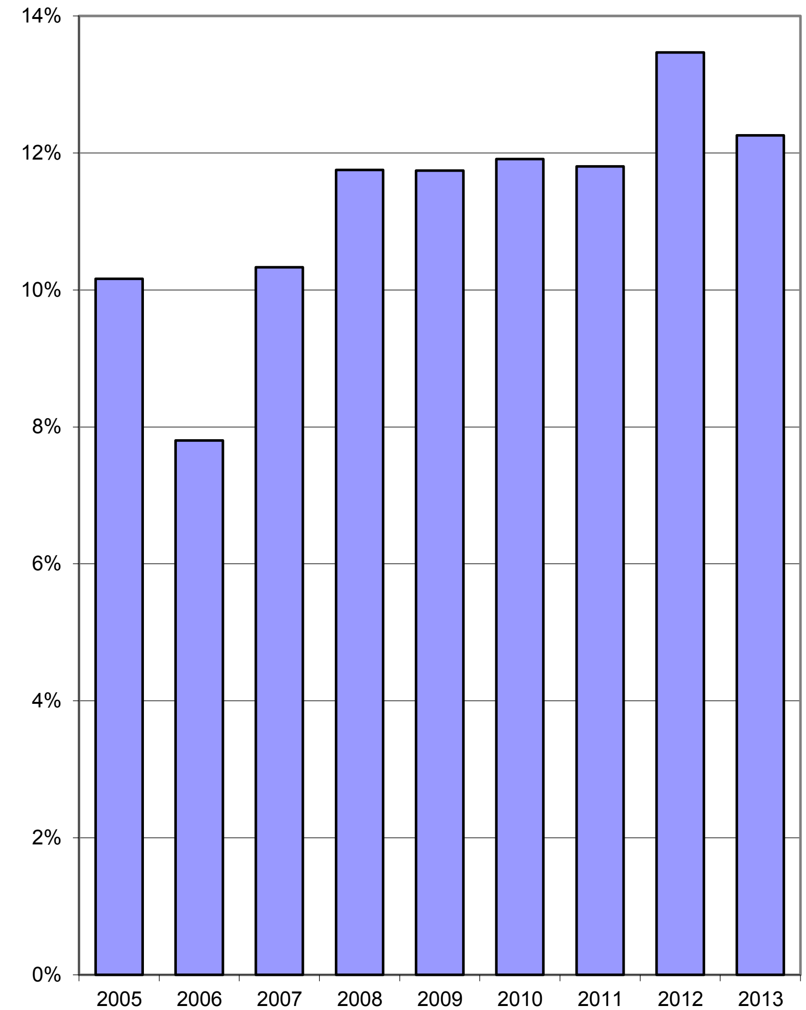
Interest Coverage
(EBIT/Interest Charges)



Financial Statement Return on Assets
(Net Income/Total Assets)



Financial Statement Return on Equity
(Net Income/Shareholders' Equity)



General Customer Information

System Gas Customers *

	ENBRIDGE	UNION	NRG	TOTAL
Low Volume	1,804,896	1,227,681	7,755	3,040,332
Large Volume	8,863	5,236	6	14,105

Total Number of Customers

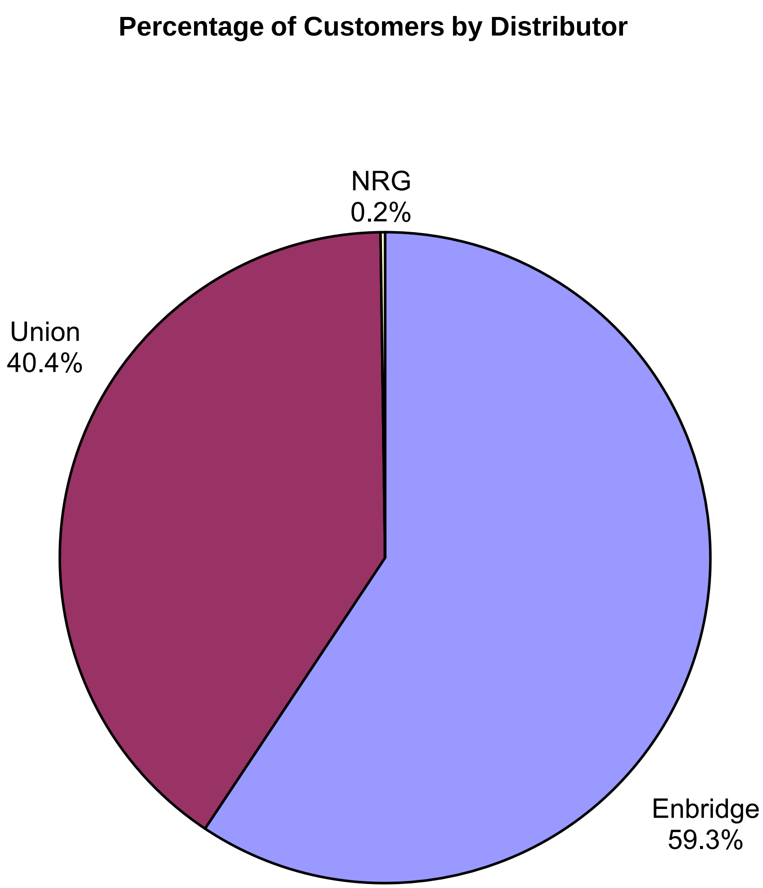
	ENBRIDGE	UNION	NRG	TOTAL
Total (includes customers of marketers)	2,052,387	1,398,680	7,767	3,458,834

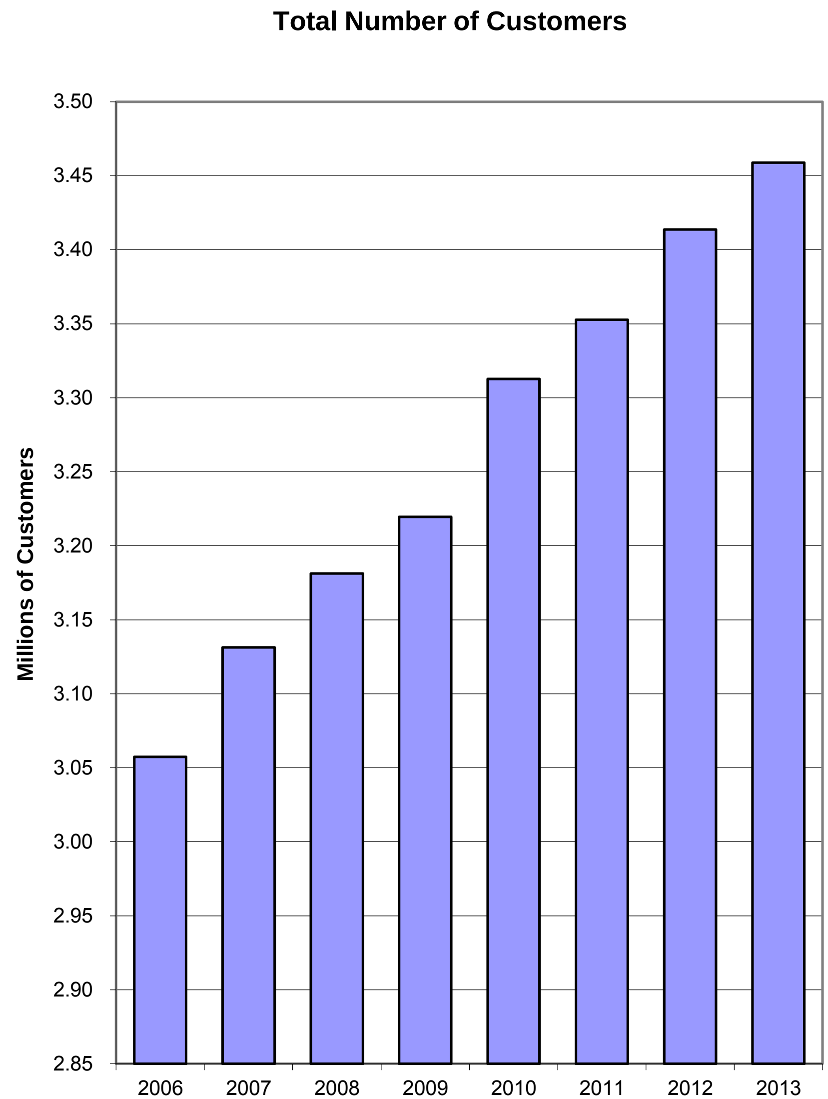
Service Quality Requirements

	ENBRIDGE	UNION	NRG
Call Answering Service Level (OEB Minimum Standard: 75%)	75.90%	78.40%	99.30%
Number of Calls Abandon Rate (OEB Standard: not exceed 10%)	2.80%	3.80%	0.70%
Meter Reading Performance (OEB Standard: not exceed 0.5%)	0.50%	0.20%	0.00%
Appointments Met within Designated Time Period (OEB Minimum Standard: 85%)	94.20%	97.80%	99.20%
Time to Reschedule Missed Appointments (OEB Standard: 100%)	94.96%	99.90%	100.00%
Emergency Calls Responded within One Hour (OEB Minimum Standard: 90%)	96.10%	97.90%	100.00%
Number of Days to Provide a Written Response (OEB Minimum Standard: 80%)	94.50%	100.00%	0.00%
Number of Days to Reconnect a Customer (OEB Minimum Standard: 85%)	92.60%	92.20%	94.40%

*Low Volume Customer - Less than 50,000 cubic meters/year; Large Volume Customer - 50, 000 cubic meters/year or more.

N/A - Denominator is zero.


Percentage of Customers by Distributor
NRG
0.2%
Union
40.4%
Enbridge
59.3%


Total Number of Customers
Millions of Customers
3.50
3.45
3.40
3.35
3.30
3.25
3.20
3.15
3.10
3.05
3.00
2.95
2.90
2.85
2006
2007
2008
2009
2010
2011
2012
2013

Cross-Reference to Uniform System of Accounts

	Aggregation of Trial Balance (RRR section 2.1.7) accounts
Cash	Accounts 130-131 if debit balance
Accounts Receivable - Net	Accounts 132+140-147
Gas Inventories	Accounts 152+153
Other Current Assets	Accounts 150+151+160-163 + 256 if debit balance
Property, Plant & Equipment	Accounts 100-116
Long Term Investments	Accounts 120-123
Deferred Charges	Accounts 170-179
Other Non-Current Assets	Accounts 180-183 + 276 if debit balance
Bank Overdraft, Loans and Notes Payable	Accounts 130-131 if credit balance + 250
Accounts Payable & Accrued Liabilities	Accounts 251+252+254+259
Other Current Liabilities	Accounts 253+255+257+260+263
Income Taxes Payable	Account 256 if credit balance
Current Portion of Long-term Loan	Accounts 258+262
Long-term Debt	Accounts 220-249
Total Debt	Accounts 130-131 if credit balance + 220-249 + 250 + 258 + 262
Deferred Income Taxes	Account 276 if credit balance
Other Non-Current Liabilities	Accounts 270+271+278+279+290
Share Capital Retained Earnings	Accounts 200-216
Operating Revenues	Account 300
Other Income	Account 319
Gas Cost, Operating and Maintenance Expenses	Accounts 301-305+311+321+326-331
Interest Expense	Accounts 320+322+323
Miscellaneous Income (Expense)	Accounts 307+308+310+312-316+324+325+333
Income Taxes (Current and Deferred)	Account 306
Extraordinary Items	Accounts 338-339

TORONTO ATMOSPHERIC FUND

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Aug. 11, 2014

Establishing a Conservation-First Policy for Ontario's Natural Gas Utilities

On March 31, 2014, the Minister of Energy directed the Ontario Energy Board (OEB) to develop a new demand side management (DSM) policy framework for natural gas that enables the achievement of all cost-effective conservation. This policy will set the stage for effective natural gas conservation practice in Ontario – key to achieving greenhouse gas reduction targets.

Toronto Atmospheric Fund (TAF) is a non-profit corporation established in 1992 and endowed by the City of Toronto. TAF's mandate is to advance urban solutions to climate change and air pollution. In Toronto, a primary source of greenhouse gas emissions is the use of natural gas in buildings, so the recent directive by the Ontario Minister of Energy provides a critical opportunity to help achieve greenhouse gas reduction targets in Toronto and across the Province. For more about TAF's mandate and accomplishments, please see our website at www.toronto.ca/taf

To support discussion around developing a new DSM framework, TAF has commissioned a series of papers on key issues relevant to implementing the Minister's "all cost-effective DSM" directive:

- Savings Goal and Budget Setting
- Cost-Effectiveness Screening
- Performance Measurement
- Performance Incentives
- Integration of Gas and Electricity Conservation Efforts
- Are Ontario Gas Utilities' Efficiency Programs Worth It?

As requested by OEB Applications Advisor Josh Wasylyk, TAF is filing these discussion papers with the OEB as reference materials for proceeding number EB-2014-0134, as they are relevant for the Board's consideration in its development of the new DSM framework.

The papers have been prepared for TAF by Chris Neme, Energy Futures Group, with research support from TAF's Policy Researcher, Rebecca Mallinson. The views and ideas expressed in these discussion papers are presented by the Toronto Atmospheric Fund to support the discussion around developing a new gas DSM policy framework.

For further information or for questions or comments on these discussion papers, please contact:

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Summary of Discussion Paper Recommendations

Savings Goal and Budget Setting

- DSM savings goals should – in accordance with the Minister of Energy's directive – aim to realize all available cost-effective energy efficiency resources.
- To do this, savings targets should be informed by bottom-up DSM potential studies and by the experience of other jurisdictions with similar "all cost-effective conservation" goals.
- The experience of U.S. jurisdictions indicates that in order to achieve the mandate of pursuing all cost-effective gas DSM, Ontario's savings targets should be at least 1% of total gas sales, and DSM budgets should be at least $200 million per year (i.e. more than three times Ontario utilities' historical annual spending on DSM).

Cost Effectiveness Screening

- Two key principles should guide the selection and application of a primary cost-effectiveness test: 1) the test should reflect the policies of the jurisdiction in which it will be used, and 2) costs and benefits should be treated symmetrically.
- With respect to test selection, every cost-effectiveness test must include utility costs and benefits, but the types of additional benefits that are included should be a function of government policies relative to those impacts (i.e. participant impacts, additional low-income impacts, health impacts, climate change impacts, other environmental impacts, etc.).
- In light of Ontario government policies that indicate concern over all these impacts, it seems appropriate for Ontario to use a full societal cost test to assess DSM activities. At a minimum, given the government's clear targets for greenhouse gas (GHG) emission reductions, GHG emission externalities should be incorporated into cost-effectiveness screening.
- With respect to applying cost-effectiveness tests, if costs to DSM program participants are included in cost-effectiveness calculations, then benefits participants should also be included (at a minimum, by using default adders for non-resource, non-energy benefits).
- If benefits to participants are not included in cost-effectiveness calculations, then the participant perspective should be excluded from the analysis altogether. (This would be analogous to moving from a TRC test to a PAC test, or from a SCT to a PAC test with environmental externalities).

Performance Measurement

- At least once every three years, all DSM programs should undergo some form of impact evaluation; that includes not only key verification activities, but also some form of measurement (e.g. whole facility billing analysis, end use metering, calibrated building simulation modeling).
- Impact assessment of the very large custom C&I programs should continue to be conducted through the Custom Project Savings Verification (CPSV) process, but with increased emphasis on on-site measurement, and removing utilities from the role of hiring and overseeing CPSV firms.
- A minimum of 3% of DSM budgets should continue to be set aside for evaluation, with higher amounts to be encouraged if required in the short term to address key data uncertainties.
- The deadline for filing annual audit reports should be pushed back from the end of June to at least the end of July in order to facilitate more extensive field work by CPSV firms

Performance Incentives

- Hold Ontario's incentives to current levels or increase only very modestly, even if utilities' DSM budgets increase dramatically.
- Examine trends in Ontario gas utilities' recent incentive earnings to determine whether incentive thresholds are set at appropriate levels, and to ensure that utilities are only earning the maximum incentives for truly exemplary performance.
- Existing performance incentive metrics are generally consistent with best practice across North America, but would benefit from some adjustments:
    - Allocate each performance metric a portion of the incentive cap (in order to eliminate the problem of over-performance on easy metrics being able to compensate for poor performance on others).
    - Ensure that incentives meant to encourage deep savings are directed toward savings achievements in the neighbourhood of 30% in existing buildings and 20% better than code in new construction. Deep savings metrics might also need to be defined over a longer period that 1 year.
- Reintroduce a lost opportunity metric to ensure that programs are encouraging participants to pursue all available cost-effective conservation opportunities.
- Consider introducing a geo-targeting metric to reward utilities for geographically targeting DSM efforts in such a way as to avoid new investments in transmission and distribution infrastructure.

Gas-Electric Integration

- Collaboration can occur to varying degrees, from "coordination" (consistency in program design) to "integration" (joint delivery of programs).
- In addition to greater collaboration between gas and electricity utilities, there is also potential for greater collaboration between the two gas utilities.
- Potential benefits of coordinated and/or integrated DSM programs include: lower program costs, enhanced reach, greater clarity in the market, and lower transaction costs for consumers.
- Coordination and/or integration are most important for programs that target market transformation, mass markets, and multi-measure, whole-building retrofits.
- While it is neither practical nor desirable to require collaboration, the gas utilities could be required to explore/endeavour to collaborate on program design and delivery with the OPA and the six largest electric utilities, and to document these efforts in their DSM reports.
- The utilities should be required to examine fuel-switching options and encouraged to pursue opportunities that are cost-effective and reduce greenhouse gas emissions; for instance deployment of heat pumps for heating.

Are Ontario Gas Utilities' Energy Efficiency Programs Worth It?

- Conservation is much cheaper than supply – Enbridge and Union Gas' programs cost \$0.03 - \$0.06 per m^3 to save natural gas, which is much less than the \$0.30 to \$0.35 per m^3 it costs the average Ontario customer to buy it.
- The \$62 million Union and Enbridge Gas's spent on efficiency programs will save their customers approximately \$338 million (net) on their gas, electric and water bills.
- Delivering energy efficiency tends to be more labour-intensive than delivering gas, which means that investments in energy efficiency create local green jobs.
- Lower energy bills make businesses more competitive, and when consumers spend their energy bill savings in the wider economy, this also contributes to local economic development.
- The measures installed as a result of Enbridge and Union's 2012 energy efficiency programs will reduce carbon dioxide emissions by 6.4 million tonnes over the course of their lifetimes – this is equivalent to taking nearly one quarter of Ontario's cars and light trucks off the road for a year.
- Reducing natural gas use by just 1% per year starting in 2015 would lower GHG emissions by 2.4 megatonnes by 2020 and achieve about 15% of Ontario's 2020 GHG reduction target.

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2014 OEB Gas DSM Framework Issue Paper:

Savings Goal and Budget Setting

On March 31, 2014, the Ontario Energy Minister issued a Directive that the Ontario Energy Board (OEB) establish a new gas DSM framework that will enable the province's regulated gas utilities to acquire all cost-effective energy efficiency resources. Among the most important elements of that framework will be guidance on how both savings goals and DSM budgets for meeting those goals are to be established. This paper addresses those issues, making clear that savings and budget levels will need to increase substantially to comply with the Minister's directive.

Savings Goals

The Minister's directive clearly states that the goal should be to acquire all cost-effective efficiency resources. Thus, savings goals should be based on a determination of how much efficiency could be acquired. Since there is no single "formula" or even a single type of study or analysis for making that determination, some judgment is needed and that should be informed by several types of information including potential studies and the experience of other jurisdictions with similar objectives.

Potential Studies

Efficiency potential studies can be a useful tool for informing savings goals, as they provide an objective assessment of efficiency potential that is based on the size and characteristics of local markets for efficiency products and services.

However, they also have some important limitations. First, they produce inherently conservative results because, among other things, they cannot a) anticipate new efficiency technologies that will develop over time, b) anticipate reductions in the cost of efficiency measures that can develop over time, c) imagine the full range of custom efficiency measures for large commercial and industrial customers (i.e. measures whose application may be specific not only to a particular industry, but even to a particular facility), and d) anticipate innovations in the design and delivery of efficiency programs that can either reduce costs or increase effectiveness in acquiring savings.[1]

[1] For further discussion of these and other conservatisms see: Goldstein, David B., "Extreme Efficiency: How Far Can We Go If We Really Need To?", 2008 ACEEE Summer Study Proceedings, Volume 10, pp. 44-56

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A related concern is that potential studies often rely on very simplistic ways of forecasting how much of the economic potential is actually "achievable". For example, many assume that market penetration is entirely a function of customer paybacks and make largely untested assumptions about customers' willingness to invest in efficiency at different payback periods. In reality, achievability is a function of the nature and severity of a variety of different market barriers – only some of which are financial – to the adoption of an efficiency technology. DSM experience also suggests addressing financial concerns is important, but other benefits of efficiency – including improved comfort, improved building durability, improved business productivity and many others – can often be used effectively to sell efficiency. Put simply, efficiency programs must be carefully designed to both address all market barriers and to leverage other benefits that efficiency measures offer – using a variety of tools including education, training, financial incentives, financing, labeling/certification, marketing, etc. It is important to recognize that the market barriers and market opportunities vary considerably from measure to measure and market to market. It is usually not possible – i.e. typically well beyond the budget available – for contractors conducting potential studies to separately assess all of the barriers and opportunities for all measures and to then separately develop market penetration estimates for each measure and market given the nature of those barriers. As a result, regulators in at least one jurisdiction (California) have simply assumed that 70% of economic potential can be captured.[2]

One possible additional and critically important limitation is that many efficiency potential studies rely on avoided costs that do not fully capture the value of efficiency (see TAF's companion paper on cost-effectiveness screening).

No gas efficiency potential studies have been recently completed in Ontario. The last Enbridge Gas Distribution potential study was completed in 2009 -- it suggested that maximum achievable potential was approximately 12% over a ten year period, an average of 1.2% per year.[3] The last Union Gas assessment of efficiency potential was a 2011 update to a 2008 study -- it estimated that maximum achievable potential was approximately 14% over a ten year period, an average of nearly 1.4% per year.[4] Both the Enbridge and Union studies assumed that only 46% of economic potential could be acquired through DSM. As noted above, that is lower than California regulators and other studies have suggested is possible. Also, neither

[2] California Public Utilities Commission, "Interim Opinion: Energy Efficiency Portfolio Plans and Program Funding Levels for 2006-2008 – Phase 1 Issues", Decision 05-09-043, September 22, 2005.
[3] Marbek Resource Consultants, "Natural Gas Energy Efficiency Potential: Update 2008", presented to Enbridge Gas Distribution, September 2009.
[4] ICF Marbek, "2008 Natural Gas Efficiency Potential Study with 2011 Summary Report Update", submitted to Union Gas, July 2011.

study fully considered the savings potential from (typically) low cost operational efficiency improvements in commercial buildings, which can be substantial.[5]

In addition to the limitations discussed above, the most recent Ontario studies are now old enough that they cannot reflect changes in the understanding of gas efficiency potential. Moreover, it is not clear that the avoided costs they used to value the benefits of efficiency either fully valued all of the benefits of efficiency (e.g. the benefits of deferring capital investments in transmission and/or distribution); nor is it clear that the avoided cost values for the benefits that they did assess are appropriate for today's market conditions.

Enbridge Gas is currently conducting a new potential study. However, it is not clear whether the study will assess maximum achievable cost-effective potential because the terms of reference for the study were developed before the Ontario Energy Minister's directive was issued. The Minister's directive also requires that a study of achievable natural gas efficiency potential in Ontario be conducted every three years (in coordination with the Ontario Power Authority's assessment of electric efficiency potential). However, the next such study is not required to be completed until June 1, 2016. This likely limits the ability of the OEB and other parties to rely extensively on potential studies to inform goal setting for the near term (i.e. 2015).

Experience from Other Jurisdictions with Similar Objectives

Another important reference point for establishing "all cost-effective" savings goals should be the experience of other jurisdictions, particularly those also operating under an "all cost-effective" mandate and with similar climates[6]. Their experiences should be assessed both in aggregate – i.e. across all customers and sales – and at the sector level; the latter is important because achievable efficiency potential can vary substantially from sector to sector, particularly over short to medium time horizons. For example, savings potential in the industrial sector is often viewed as more substantial – at least in the short and medium terms – than potential in the residential sector.[7] Thus, utilities or jurisdictions with proportionally greater sales to residential customers will typically have lower total savings as a percent of total sales than utilities or jurisdictions with proportionally greater sales to industrial customers, particularly larger industrial customers.

[5] See testimony from Environmental Defense witness Ian Jarvis in EB-2012-0451.
[6] Similar climates is important because much of gas use in residential and commercial buildings in northern climates is related to space heating.
[7] Residential savings potential is still quite substantial, but because it requires retrofit treatment of many more customers, it will take longer to fully acquire the potential.

Right now, there are only two other "cold climate jurisdictions" in North America that have a mandate to pursue all cost-effective gas DSM: Massachusetts and Rhode Island. Both of those jurisdictions are proposing to capture savings equal to about 1.1% of total (all sector) sales in their current plans for 2015.[8] Though not operating under an "all cost-effective" mandate, gas utilities in Vermont (1.1% in 2013) and Minnesota (1.5% in 2015 plans) have comparable savings levels (again, in aggregate across all sectors). In both Massachusetts and Rhode Island, approximately 50% of gas sales are to residential customers and only about 20% to industrial customers.[9] Gas sales in Ontario are less heavily weighted towards the residential sector and more heavily weighted towards the industrial sector. Thus, one would expect savings potential in Ontario to be higher than in Massachusetts and Rhode Island, at least in the short and medium term.

Budgets

Given the Ontario Energy Minister's directive, the budgets made available for DSM on Ontario should be sufficient to capture all cost-effective gas efficiency – i.e. to meet the savings targets discussed above. Ideally, the determination of how much money that would be would be based on "bottom up" assessments – market by market – of what state-of-the art energy efficiency programs would need to do, how they would be designed and the level of financial resources those designs would require to be as effective as possible. That said, the DSM budgets of other jurisdictions that are mandated and endeavoring to acquire all cost-effective gas efficiency potential (or even similarly aggressive levels of savings) can be used as a useful reference point.

Experience of Other Jurisdictions with Similar Objectives

Consider these four jurisdictions: two cold climate jurisdictions currently required to pursue all cost-effective gas efficiency resources -- Massachusetts and Rhode Island – and two others – Vermont and Minnesota – with at least comparable energy savings goals. As Table 1 shows, these four jurisdictions have annual DSM budgets that range from 3½ to 13 times (average of 8 times) greater than the current Ontario utility DSM budgets on a gas sales normalized basis. Put another way, if the Ontario gas utilities DSM budgets were to increase to levels comparable to those of leading jurisdictions, they would be at least $100 million per year per utility – at least $200 million for the province – and potentially several times that amount.

[8] Based on savings forecast in the utilities' most recently filed DSM plans and 2012 sales from the U.S. Energy Information Administration's form 176 data.
[9] U.S. Energy Information Administration data from EIA form 176 for calendar year 2012.

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Table 1: Leading Jurisdiction vs. Ontario DSM Budgets[10]

	Total Gas Sales (m^3)	Gas Sales Reference Year	Total DSM Budget	Budget Reference Year	DSM Budget per m^3 Sales
Leading Jurisdictions					
Massachusetts	6,319,346,456	2012	$ 191,766,032	2015	$0.0303
Minnesota	4,790,121,305	2012	$ 50,833,263	2015	$0.0106
Rhode Island	957,519,137	2012	$ 23,491,410	2014	$0.0245
Vermont	227,572,544	2012	$ 1,884,124	2013	$0.0083
Average					**$0.0184**
Ontario Utilities					
Enbridge	11,300,100,000	2012	$ 30,606,510	2012	$0.0027
Union	14,617,390,000	2012	$ 31,322,216	2012	$0.0021
Average					**$0.0024**

It is worth noting that many other jurisdictions across North America – including many who clearly do not have a mandate to pursue all cost-effective efficiency and are not attempting to even get close to that level of savings – have historically had DSM budgets that are considerably greater than the Ontario gas utilities' budgets. The spending metric used by the American Council for an Energy Efficient Economy (ACEEE) to compare gas DSM spending between states is: total spending per residential customer. In 2011, the Ontario gas utilities spent a combined $55.2 million on gas DSM.[11] That represents an average of about $15 per residential customer.[12] In the same year, 18 U.S. states - including the southern states of Florida and Arkansas – spent at least $20 per residential customer; 11 of those states spent at least twice as

[10] U.S. sales data from U.S. Energy Information Administration form 176 data (2012 is the most recent year for which data are available). Note that sales data for Massachusetts and Minnesota are only for sales by investor-owned utilities subject to DSM requirements and, in the case of Minnesota, exclude sales to transport customers which do not pay for or receive DSM services. Sales forecast for Enbridge Gas from EB-2012-0451/EB-2012-0433/EB-2013-0074, Exhibit I.A4.EGD.GEC.34; sales estimate for Union gas from EB-2011-0210, Exhibit C4, Tab 2, Schedule 1. DSM spending values for each state are from regulatory filings of the affected utilities in the state. DSM spending for Enbridge and Union Gas are from their respective 2012 annual reports (sometimes call "annual evaluation reports").

[11] Enbridge Gas Distribution, "2011 Draft DSM Annual Report", April 2012; and Union Gas, "Final Audited Demand Side Management 2011 Annual Report", June 29, 2012.

[12] According to NRCAN, there were 3.65 million residential gas customers in Ontario in 2011.

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much as Ontario (i.e. over $30 per residential customer).[13] Both British Columbia and Manitoba are also currently planning to spend two to three times as much on gas DSM (per m^3 of gas sales) as Ontario's gas utilities spent in 2012. Put simply, gas DSM spending in Ontario has been lagging behind not only leading jurisdictions, but even "middle of the road" jurisdictions, for a number of years.

Ramp Up Period

Though gas DSM budgets in Ontario would need to increase dramatically to get to the point where the province was acquiring all cost-effective efficiency, it would not be reasonable or prudent to expect the increase to take place immediately. Some period of ramp up would be necessary to ensure that there is sufficient time to develop new and more aggressive programs, and to increase utility and private sector delivery capability in a reasonably efficient and effective manner. The experience of the Massachusetts gas utilities may be instructive in this regard. As Figure 1 below demonstrates, Massachusetts budgeted only $38 million for gas DSM in 2009,[14] the year that a new legislative requirement to acquire all cost-effective efficiency went into effect. Spending then more than doubled the following year and continued to increase fairly linearly until 2013, at which point increases leveled off. In other words, the state ramped up to acquiring all cost-effective efficiency – with a nearly five-fold increase in budget – over the course of about 4 years.

[13] Downs, Annie et al., "2013 State Energy Efficiency Scorecard", published by the American Council for an Energy Efficient Economy, Report E13K, November 2013.
[14] Note that the 2009 budget was still more than twice per m3 of annual gas sales ($0.0060) than the current Ontario gas utility DSM budgets ($0.0024).

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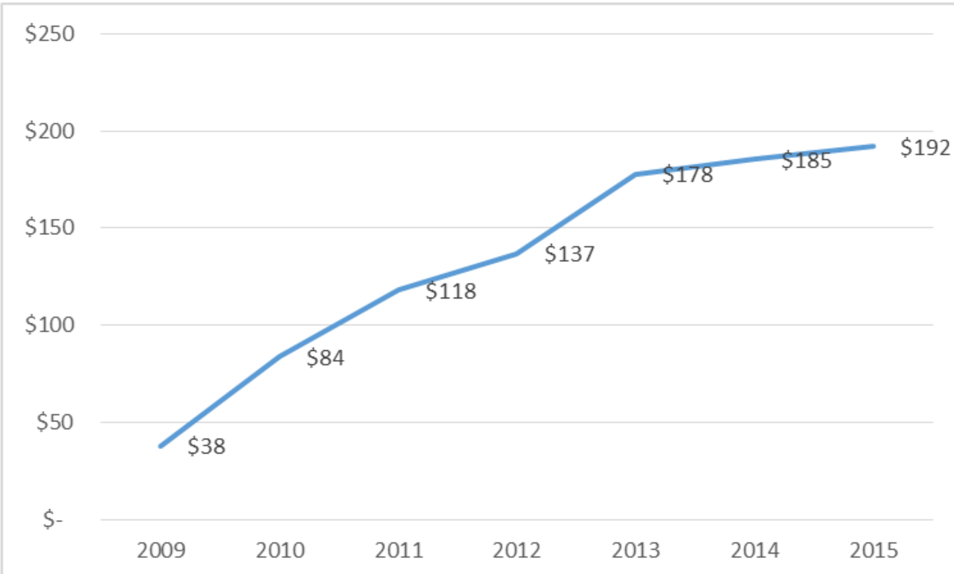
Figure 1: Massachusetts Gas DSM Budgets, 2009 to 2015 (millions of nominal dollars)[15]



Addressing Rate Impact Concerns

Historically, when the subject of potential increases in DSM spending is raised, some stakeholders have expressed concerns about resulting rate impacts. While the Energy Minister's directive to pursue all cost-effective efficiency does not include any caveats related to rate impacts, some discussion of the topic may be warranted to address common misconceptions.

To begin with, it should be emphasized that, customers' principal concern is with their total energy bill, rather than the price (rate) per unit of energy consumed; indeed, most residential and smaller business customers do not even know what their gas rate is. Any customer would prefer to have a 5% higher rate if it got a 20% reduction on consumption at the same time (resulting in a total energy bill reduction of 16%). Efficiency investments that pass a TRC cost-effectiveness screening test will, by definition, reduce the total gas bill of all customers. Thus, concerns about rate impacts associated with energy efficiency tend to be about equity (i.e. about the customers who do not participate in efficiency programs), which can be addressed by offering a broad enough portfolio of programs so that, over time, all customers have the opportunity to reap the benefits of efficiency.

[15] Budgets for 2009 through 2012 from ACEEE State Energy Efficiency Scorecards for 2010 through 2013; budgets for 2013 through 2015 from Massachusetts Department of Public Utilities order in regulatory proceedings 12-100 through 12-111, January 31, 2013.

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It is also important to recognize that there are four factors associated with DSM that could potentially affect rates:

- DSM spending, which has the effect of increasing rates;
- Avoided capital expenditures, such as on transmission and distribution systems, which have the effect of lowering rates;
- Lower demand, which has the effect of lower rates; and
- The spreading of fixed utility costs across a smaller volume of sales (commonly called utility "lost revenue") which has the effect of increasing rates.

To suggest that the last of these is a concern is tantamount to suggesting that the province would not want consumers to save energy even if savings could be acquired for free, or worse, that the province would prefer that its residents and businesses wasted more energy so that rates could go down. It is hard to imagine any such interpretation of provincial policy. Thus, the only three effects that should be of interest are the upward pressure on rates caused by DSM spending, the downward pressure on rates caused by avoided capital expenditures, and the downward pressure on rates caused by lower demand (commonly called price suppression effects).

The impact on rates of DSM spending deserves consideration. In 2012, Union Gas' and Enbridge Gas' customers were collectively forecast to consume about 26 billion m^3 of gas. Assuming that annual gas sales remain at approximately those levels, every $100 million in DSM budget would add an average of about $0.0039 to the cost of an m^3 of gas. Current residential gas costs are on the order of $0.40 to $0.45 per m^3.[16] Thus, assuming gas DSM spending was allocated approximately in proportion to sales by customer class, every $100 million in gas DSM spending in the province would result in a residential rate increase of about 1%. Thus, gas DSM spending could increase by a factor of roughly five – to $300 million between the two large gas utilities – and still add only about 3% to the average residential bill.

Moreover, that is just the cost side of the equation. The province's gas utilities have not recently estimated the value of avoided capital expenditures associated with DSM. Nor have they ever estimated the price suppression effects of lower demand resulting from efficiency programs.[17] Thus, we do not know the extent to which the impacts of DSM budgets on rates would be offset – perhaps even more than offset – by the factors that put downward pressure

[16] All costs, including commodity, cost adjustments, transportation, delivery and fixed monthly charges divided by average annual consumption of 2200 m^3 for Union Gas and 3000 m^3 for Enbridge Gas (http://www.ontarioenergyboard.ca/OEB/Consumers/Natural+Gas/Natural+Gas+Rates).

[17] See the TAF cost-effectiveness screening paper for further discussion of this topic, including estimates of the magnitude of this benefit estimated for other jurisdictions.

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on rates. In addition, beyond the impact on capital expenditures, there would be substantial (TRC) economic net benefits – literally hundreds of millions of dollars – associated with each year of DSM implementation.
Since customers ultimately care more about their total gas bill than about the cost per unit of gas consumed, the best answer to any lingering concerns about rate impacts is to ensure that DSM portfolios become substantial enough and sufficiently balanced so that all customers can access programs over time.

Conclusions

Ultimately and ideally, gas savings goals and budgets to achieve those goals should be based on a bottom-up assessment of the opportunity to acquire all cost-effective gas efficiency resources. In the meanwhile, all available evidence suggests that Ontario's gas savings goals should increase substantially – to in excess of 1% of sales per year – and that the utilities' budgets should increase fairly dramatically – by at least three-fold (i.e. to at least $200 million per year) and likely to considerably higher levels given the in-efficiency of the market.

Attribution and Use

This brief has been prepared for TAF by Chris Neme, Energy Futures Group, with research support from TAF Policy Researcher, Rebecca Mallinson. Please treat this material as 'draft' as elements may evolve during the course of discussions and in the formulation of input to the formal OEB consultation. Please note that the views and ideas expressed in these briefs are presented by the Toronto Atmospheric Fund to support the discussion around developing a new gas DSM policy framework. We welcome your views about these or other issues related to natural gas conservation policy in Ontario.

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2014 OEB Gas DSM Framework Issue Paper:

Cost-Effectiveness Screening

On March 31, 2014, the Ontario Energy Minister issued a Directive that the Ontario Energy Board (OEB) establish a gas DSM framework that will enable the province's regulated gas utilities to acquire all cost-effective energy efficiency resources. One obvious issue this raises is the definition of "cost-effective". This paper reviews the principal cost-effectiveness tests used across North America, summarizes the history of gas DSM cost-effectiveness screening in Ontario, discusses short-comings of current practice and provides recommendations for the post-2014 gas DSM framework that the OEB is charged with developing.

DSM Cost-Effectiveness Tests

Dozens of Canadian provinces and U.S. states currently require regulated gas and electric utilities to pursue DSM activities. With few exceptions (e.g. low income programs in some jurisdictions), such activities are typically required to be cost-effective. Though cost-effectiveness is often examined from a number of different perspectives, almost every jurisdiction uses one of three different tests – the Program Administrator Cost (PAC) test,[1] the Total Resource Cost Test (TRC) or the Societal Cost Test (SC) – as the primary test to determine whether DSM is cost effective. The "lens" through which each of these tests assesses cost-effectiveness is different. Figure 1 provides a summary of those three perspectives.

Figure 1: Different Perspectives of the PAC, TRC and SC Tests[2]

Test	Key Question	Impacts Included	Implications
PAC	Will utility system costs decrease?	Costs and benefits experienced by the utility system.	Limited to impacts on the utility system. Indicates net impacts on utility costs and utility bills.
TRC	Will utility system plus program participants' costs decrease?	Costs and benefits experienced by the utility system, plus other costs and benefits experienced by program participants.	By including impacts beyond the utility system, this test is essentially based on a (partial) societal perspective.
SC	Will total costs to society decrease?	Costs and benefits experienced by all members of society.	Most comprehensive assessment.

[1] Alternatively called the Utility Cost Test (PACT).
[2] Adapted from Woolf, Tim et al., "The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening", prepared for the National Energy Efficiency Screening Coalition and published by the National Home Performance Council, March 28, 2014 (http://www.nhpci.org/publications/NHPC_NESP-Recommendations-Final_20140328.pdf).

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One way of thinking about these tests is that they span a continuum of impacts. The PAC is on one end in that it focuses only on costs and benefits to the utility system. Utility system impacts are included in every test. Thus, in a way the PAC is the foundation for all cost-effectiveness screening. The SC is on the other end in that it focuses on *all* costs and benefits experienced by *all* members of society (including the utility system impacts). The TRC is in between. It adds a subset of societal impacts – the additional impacts on program participants – to the utility system impacts. Figure 2 provides more detail on the types of costs and benefits included under each test.

Figure 2: Components of the Energy Efficiency Cost-Effectiveness Tests[3]

	PAC Test	TRC Test	Societal Cost Test
Energy Efficiency Program Benefits:			
Avoided Energy Costs	Yes	Yes	Yes
Avoided Capacity Costs	Yes	Yes	Yes
Avoided Transmission and Distribution Costs	Yes	Yes	Yes
Wholesale Market Price Suppression Effects	Yes	Yes	Yes
Avoided Cost of Environmental Compliance	Yes	Yes	Yes
Reduced Risk	Yes	Yes	Yes
Other Program Impacts (utility-perspective)	Yes	Yes	Yes
Other Program Impacts (participant-perspective)	---	Yes	Yes
Other Program Impacts (societal-perspective)	---	---	Yes
Energy Efficiency Program Costs:			
Program Administrator Costs	Yes	Yes	Yes
EE Measure Cost: Program Financial Incentive	Yes	Yes	Yes
EE Measure Cost: Participant Contribution	---	Yes	Yes
Other Program Impacts (participant costs)	---	Yes	Yes

Note that what should distinguish the three tests on the benefits side of the equation is the range of non-energy benefits (NEBs) included. Under the PAC, the only NEBs included are those

[3] Copied from Woolf, Tim et al. (Synapse Energy Economics), "Energy Efficiency Cost-Effectiveness Screening in the Northeast and Mid-Atlantic States: A Survey of Issues and Practices, With Recommendations for Developing Guidance to the Regional Evaluation, Measurement and Verification (EM&V) Forum", prepared for the Regional EM&V Forum, a project of the Northeast Energy Efficiency Partnerships, October 2, 2013.

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that affect the utility's bottom line. A good example would be reduced credit and collection costs. Under the TRC, NEBs experienced by program participants should also be added (since this test, by definition, is structured to assess the combined impacts on the utility system and program participants). Examples of participant NEBs include improved comfort, increased building durability, quieter equipment operation (efficient equipment is often sold as a "premium product" with other premium features), improved aesthetics, water savings, other fuel savings, reduced waste, and improved business productivity. Under the SC, additional NEBs experienced by society should also be added. The most common are environmental impacts and public health impacts.

History of Gas DSM Cost-Effectiveness Screening in Ontario

In its landmark 1993 order on gas DSM – EBO-169 – the OEB adopted a societal cost test (SC) as the principal test to determine whether a DSM program was in the public interest; the Board ruled that any program that passed the SC should be pursued, provided it didn't lead to "undue" rate impacts.[4] Several years later, in response to a settlement agreement among a number of parties, the OEB revised its position and adopted the TRC test as its primary test of cost-effectiveness. The principal difference between the SC and the TRC, as implemented in Ontario, is that the SC included estimates of the economic benefit of reducing the environmental costs of gas use (e.g. most notably to account for the reducing the adverse impact of carbon dioxide emissions and global climate change), whereas the TRC does not include consideration of environmental externalities. The TRC test has been the primary test for gas DSM in Ontario ever since.

Problems with the Application of the TRC in Ontario

As discussed above, the TRC is nominally intended to capture all costs borne and all benefits received by both the utility energy system and participating consumers. However, its application in Ontario has been far from comprehensive in addressing those impacts. Worse still, its application in Ontario has been biased in that all relevant costs have typically been included while many categories of benefits have not been. Of the eight categories of benefits that Figure 2 suggests should be captured under the TRC, only one – avoided energy costs – has typically been fully incorporated into TRC screening. The other seven categories of benefits appear to have been either totally or partially excluded from cost-effectiveness analyses to date. Each of the omissions is discussed briefly below.

[4] Ontario Energy Board, A Report on the Demand-Side Management Aspects of Gas Integrated Resource Planning for: The Consumers' Gas Company Ltd., Centra Gas Ontario Inc. and Union Gas Company, E.B.O. 169-III, Report of the Board, July 23, 1993.

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- **Avoided capacity costs**. The current Board guidelines for gas DSM, published in June 2011, clearly required the utilities to included avoided capital costs. For example, DSM can reduce the amount of investment required to provide gas storage capacity for peak periods. However, it is not clear that the Union or Enbridge currently include any avoided capital costs in their avoided costs and cost-effectiveness screening.
- **Avoided transmission and distribution (T&D) system costs**. Another element of avoided capital costs is avoided investment in the T&D system. Again, however, as became apparent in the recent GTA pipeline case, the utilities have not recently included avoided T&D capital costs in their cost-effectiveness screening of efficiency programs.[5] The magnitude of avoided gas T&D benefits will be utility and location specific. However, it is worth noting that Enbridge Gas' historic investment in efficiency likely delayed the date at which the utility estimated the pipeline project was needed. Moreover, there was substantial evidence presented in the GTA proceeding to suggest that a more substantial investment in efficiency could have continued to cost-effectively defer at least a portion of the multi-hundred million dollar project even further into the future.[6]
- **Wholesale market price suppression effects**. In a competitive market, when demand for gas or electricity goes down, the most expensive source of gas or power is no longer purchased and the market clearing price for all remaining purchases goes down. The Ontario gas utilities have never included the benefits of such wholesale market price suppression effects in their DSM cost-effectiveness screening. Though the magnitude of such reductions in prices are typically not large, the total value of even a small reduction in price can be substantial because it affects every m^3 of gas that is sold. There are two important sub-categories of these benefits. The first is a reduction in price – and therefore cost – of direct use of gas by consumers. The second is a reduction in price of gas used for electric generation, which results in a reduction in electricity prices and therefore a reduction in electricity costs borne by consumers. A recent study for the New England states found that the combination of these two price suppression effects (most of the benefit was from reduced electricity prices) would add an average of nearly $113 to the net present value of an MMBtu of gas heating savings over a 15 year measure life.[7] If the same

[5] The evidence of Paul L. Chernick in EB-2012-0451/0433/0074 found that, if the data provided were typical, "the avoided cost of routine load-related reinforcements would be…roughly $\$0.23/m^3$ on an annual basis for average retail load." (p. 21)

[6] See testimony of Chris Neme and Paul Chernick on behalf of the Green Energy Coalition, as well as testimony of Ian Jarvis on behalf of Environmental Defense in EB-2012-0451.

[7] Hornby, Rick et al., "Avoided Energy Supply Costs in New England: 2013 Report", prepared for the Avoided-Energy-Supply-Component (AESC) Study Group, July 12, 2013, pp. 1-19 and 1-20. Levelized annual New England benefit values converted to a 15 year NPV using the same real discount rate used in the study.

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values were applicable to Ontario, the net present value per m^3 of heating savings would be approximately $4.11.[8] That is nearly double the 15-year NPV of avoided energy for space heating measures that was used in 2013 by Enbridge.[9] Put another way, if the New England price suppression effects were applicable to Ontario, they would, by themselves, effectively triple Enbridge's current estimated value of gas savings. To be sure, the value of price suppression effects can vary considerably from region to region; there are differences even among the six New England states, and Ontario's gas import capability is not as constrained as New England's. However, if nothing else, this suggests that it is imperative that an assessment of price suppression effects be independently estimated for Ontario's gas utilities and that the benefits should be included in cost-effectiveness screening.

- **Avoided cost of environmental compliance**. Utilities should include in their avoided costs both the costs of complying with environmental regulations that have become law and the potential cost – possibly probability weighted – of the cost of complying with new environmental regulations that have a reasonable probability of being adopted in the future. To not account for at least the probability of such costs is to consciously understate the benefits of efficiency. In context of Ontario's gas utilities operations, for example, there should be some value attached to the reduction in carbon emissions because the province, through its 2007 Climate Change Action Plan, has set an objective of reducing greenhouse-gas emissions 15% from 1990 to 2020 and 80% by 2050 and will fall short of those targets absent new regulations or unexpected changes in the market. Moreover, "emissions due to natural gas consumption remain a significant barrier to future progress."[10] However, the Ontario utilities do not currently account for the likelihood of future carbon emission constraints in the estimates of avoided costs.
- **Reduced risk**. One benefit of efficiency is that it reduces consumers' exposure to the risk of future fuel price volatility – a phenomenon that the recent unexpected spike in winter gas prices has clearly demonstrated. To address this and related risks, the Vermont regulator (the Public Service Board) has required that all efficiency measure costs be reduced by 10% (to reflect the comparative certainty of those costs) when performing cost-effectiveness screening. An alternative would be to provide an "adder" to avoided energy costs (to reflect their relatively lower certainty). Ontario's gas utilities have never considered this benefit in their TRC screening.

[8] Conversion based on assumed 35,000 BTU/m3 and an average 2013 exchange rate of $0.96 USD to $1.00 CDN.
[9] Enbridge Gas Distribution, 2013 Demand Side Management Draft Evaluation Report, May 7, 2014, p. 119.
[10] Environmental Commissioner of Ontario, "A Question of Commitment: Review of the Ontario Government's Climate Change Action Plan Results", Annual Greenhouse Gas Progress Report 2012, December 2012. (p. 13)

- **Utility NEBs**. The Ontario gas utilities have never included the value of reduced credit and collection costs in their cost-effectiveness screening. It should be noted that the Board's 2011 DSM guidelines did lower the cost-effectiveness threshold required for low income programs to a benefit-cost ratio of 0.7, in part to capture the effects of such benefits. However, low income customers are not the only customers that impose credit and collection costs on the system. An analysis of the magnitude of such costs should ideally be conducted to assess both their total value and the portion of that value that is associated with non-low income program participants. The non-low income portion of the value should then be added to other avoided costs. Alternatively, Ontario could develop assumptions regarding such impacts by extrapolating from results of studies in other jurisdictions.
- **Participant NEBs**. Historically, the Ontario gas utilities have included in screening only what are sometimes called "resource NEBs" – i.e. the values of electricity savings and water savings. There is extensive literature on participant NEBs which suggests that the value of numerous other "non-resource NEBs" can be substantial. Indeed, many leading efficiency programs across the continent often actively sell customers on efficiency investments by aggressively promoting non-energy benefits such as improved comfort and improved business productivity. An increasing number of jurisdictions have begun to address this issue by either directly quantifying such NEBs or by adopting across-the-board participant NEBs "adders" to avoided costs. For example, the Massachusetts gas utilities now routinely include non-resource benefits such as improved comfort and improved health and safety in their cost-effectiveness screening. Results from 2013 suggest that the value of those non-resource benefits for their home retrofit program had an NPV of nearly \$3 per m^3 saved over an average program measure life of 18 years.[11] Those values were derived after extensive study of the value of different kinds of participant NEBs using the Massachusetts utilities' evaluation budgets. By comparison, Enbridge's avoided energy costs for space heating savings were \$2.55 per m^3 saved (for the same 18-year measure life).[12] In other words, the Massachusetts NEBs for this program were greater than Enbridge's total avoided energy costs. That comparison is consistent with a recent study that found that participant NEBs for home weatherization programs averaged between 89% and 140% of energy or bill savings.[13] In Vermont, the state regulators have taken a simpler and more conservative approach. They now require that 15% be added to the calculated energy benefits of

[11] Massachusetts' utilities 2013 4th quarter reports.
[12] Enbridge Gas Distribution, 2013 Demand Side Management Draft Evaluation Report, May 7, 2014, p. 119.
[13] Skumatz, Lisa, "Non-Energy Benefits/Non-Energy Impacts (NEBs/NEIs) and their Role & Values in Cost-Effectiveness Tests: State of Maryland", Prepared for the Natural Resources Defense Council, March 31, 2014.

efficiency,[14] with an additional 15% adder for low income programs. The regulators acknowledge that these are default values are intentionally "conservative" and will be revisited in the future.[15]

In short, the current application of the TRC test in Ontario produces results that are skewed against efficiency because it includes all of the costs that should be captured in the "utility system plus participant" perspective on cost-effectiveness that the test is purported to provide, but only a portion – and arguably only a minority – of the benefits that should be captured. Ontario is not unique in this regard. Many other jurisdictions that use the TRC have also not fully captured all of the benefits of efficiency. However, as some of the examples provide above demonstrate, that has changed in a number of jurisdictions. Similar changes are necessary in Ontario regardless of government policy.

Recommendations for the Future

A group of DSM experts from across North American recently developed and published a new set of guidelines – embodied by what it calls the Resource Value Framework (RVF) – for assessing the cost-effectiveness of efficiency programs.[16] The framework does not promote the universal adoption of any particular screening test. Rather, it articulates a number of key principles that should guide both the selection of a primary cost-effectiveness screening test and the use or application of the selected test. Ontario would do well to follow this guidance.

Selection of Cost-Effectiveness Test

One of the key principles of the framework is that the selection of the primary cost-effectiveness test should be based on the policies of the jurisdiction. As noted above, there is a continuum of options, starting from the least comprehensive utility system perspective (the perspective addressed by the PAC) and ending at the most comprehensive societal perspective in which all costs and benefits to all members of society are assessed. There are a potentially unlimited number of points in between. Put simply, every test must include utility system benefits and costs; the determination of which additional types of benefits and costs to include

[14] This adder is over and above the value of other energy/fuel savings, water savings and customer operations and maintenance savings, which were already being captured in Vermont screening.
[15] State of Vermont Public Service Board, "Order Re Cost-Effectiveness Screening of heating and Process-Fuel Efficiency Measures and Modifications to State Cost-Effectiveness Screening Tool", Order entered 2/7/2012, pp. 26-27.
[16] Woolf, Tim et al., "The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening", prepared for the National Energy Efficiency Screening Coalition and published by the National Home Performance Council, March 28, 2014 (http://www.nhpci.org/publications/NHPC_NESP-Recommendations-Final_20140328.pdf).

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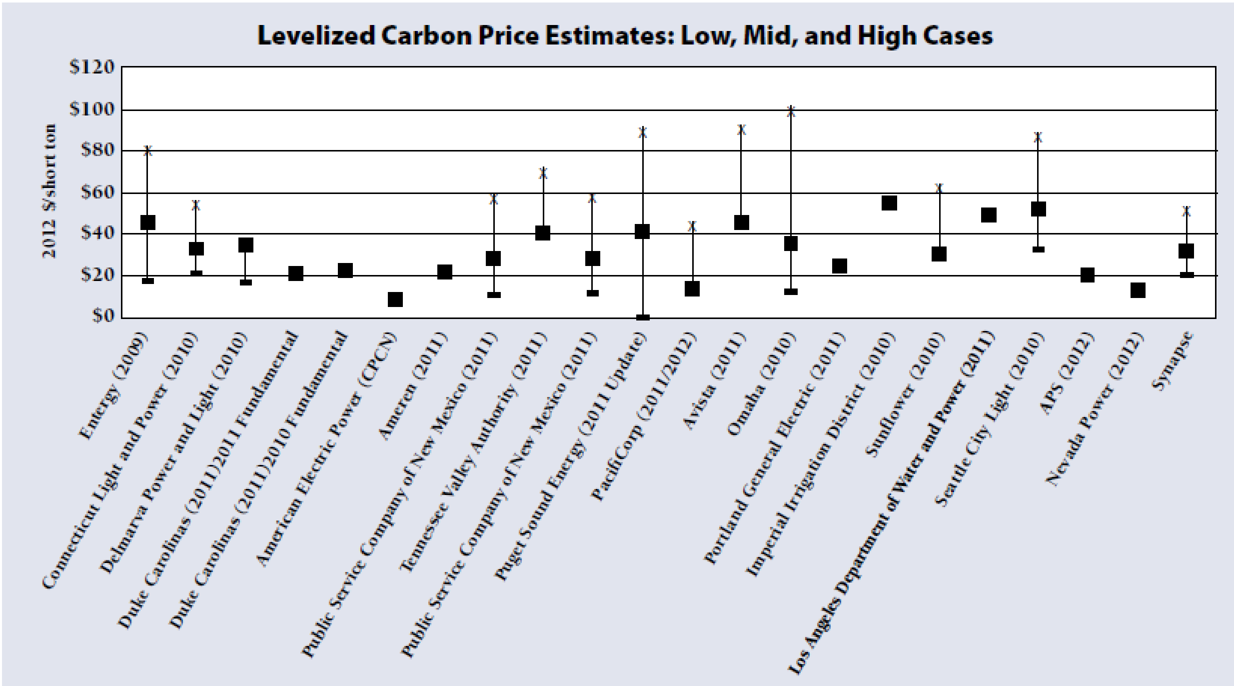
– participant impacts, additional low income impacts, health impacts, climate change impacts, other environmental impacts, etc. – should be a function of government policies relative to those impacts. Since the Ontario government has adopted policies that indicate concern over all of these impacts, it would seem appropriate to adopt the full societal test.

At a minimum, the Board should require the addition of carbon dioxide emission externalities to cost-effectiveness screening. As discussed above, the provincial government has not only expressed concern about climate change, it has established clear targets for carbon emission reductions and the province's Environmental Commissioner has asserted that those targets will not be met without greater effort, including greater effort in the gas sector. Moreover, the Ontario Energy Minister clearly identified the benefit of reduced emissions of environmental pollutants – "including greenhouse gas emissions" – as part of the rationale for the directive to put conservation first in the province's long-term energy plan.

Note that the development of a carbon emissions externality factor was quite challenging back in the early to mid-1990s. Ontario was truly on the cutting edge at the time. Nevertheless, a factor was developed and used. Nearly twenty years later, numerous jurisdictions now routinely include a carbon emissions externality value in integrated resource planning and/or cost-effectiveness screening of energy efficiency. A subset of those recently analyzed by Synapse Energy Economics is shown in Figure 3 below. Thus, the OEB would have numerous reference points for consideration in developing a new value for Ontario screening.[17]

[17] Including carbon emission costs is appropriate for comparing gas supply to conservation (which has few if any negative externalities) but caution should be exercised when comparing supply options, in which case all significant externalities should be included to avoid skewed selections. For example, when comparing electricity generation choices uninsured nuclear risk is a major externality that can and should be monetized.

Figure 3: Levelized Carbon Emission Prices from Utility IRPs[18]



Application of Cost-Effectiveness Test

A second key principle of the RVF is that costs and benefits should be treated symmetrically. That is, whatever screening perspective is taken – whether the limited utility system perspective or the expansive societal perspective or something in between – screening must include the full range of costs and benefits associated with the perspective.

To use a concrete example, it is inappropriate to include participants' costs in the TRC or SC (remembering that the TRC is supposed to address the combination of utility system and program participant impacts, and the SC is supposed to address all impacts on society) if one also does not include all of participants' benefits. That is not to say that untold millions of dollars must be spent to quantify every conceivable participant NEB. However, it would equally inappropriate to assume – implicitly or explicitly – that NEBs have no value. There needs to be practical limitations imposed. At a minimum, screening should include default participant non-resource NEB adders. If for any reason that is deemed to not be appropriate, then it would be better – more balanced – to exclude the participant perspective from the analysis altogether.

[18] Figure copied from Woolf, Tim et al. (Synapse Energy Economics), "Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for 'Other Program Impacts' and Environmental Compliance Costs", published by the Regulatory Assistance Project, November 2012.

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That would be analogous to moving from the TRC to the PAC. It would also be analogous to moving from the SC to the PAC plus environmental externalities.

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2014 OEB Gas DSM Framework Issue Paper:

Performance Measurement

Current Ontario Framework

In June 2011, the Ontario Energy Board (OEB) issued a new set of demand-side management (DSM) guidelines for the province's two gas utilities. Among the key issues those guidelines addressed was the assessment of the actual performance of the utilities DSM programs, particularly in comparison to performance goals or metrics that would be established in the utilities' DSM plans. The same OEB guidelines allow the utilities to earn substantial financial incentives for their shareholders for meeting or exceeding their goals. Subsequent to the OEB's publication of its DSM guidelines, the utilities filed their plans. As part of those plans, the utilities included new proposals that expanded on the OEB's guidelines regarding performance measurement. Those proposals were ultimately approved by the OEB. The result is the gas DSM performance measurement framework in place in Ontario today. What follows is a summary of key elements of the current framework:

- **Evaluation plans**. The utilities are required to file plans for how they will evaluation the effectiveness of their DSM programs as part of their three-year DSM plans.
- **Evaluation budgets**. The utilities are required to identify the portion of their DSM budgets that will be spend on evaluation. For the approved 2012-2014 plans, the utilities' proposed evaluation budgets were approximately 3% of their total DSM budgets.[1]
- **Prescriptive savings assumptions**. Each year the utilities jointly file savings and other assumptions (e.g. measure life and incremental cost) that they expect to use when estimating the impacts of prescriptive efficiency measures. Those assumptions are based on both data collected in Ontario and on research and evaluation conducted in other jurisdictions. Prescriptive efficiency measures are typically measures for which *average* savings across an entire population of program participants can be estimated with some confidence and for which site-specific estimates of savings would be prohibitively expensive (e.g. for measures which are rebated and/or installed in substantial quantities in homes or smaller businesses). Though the OEB's 2011 guidelines make clear that the utilities must use the best available information on savings at the time that their annual savings claims are made (typically in the Spring for the previous year – see below), the filed assumptions

[1] Enbridge's ranged from 2.4% in 2012 to 2.8% in 2014 (EB-2012-0394, Exhibit B, Tab 1, Schedule 5). That was for direct costs only; it did not include costs for tracking and reporting, management of research and costs associated with stakeholder engagement. Union's was 3.2% (EB-2011-0327, Exhibit A).

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serve as default assumptions in the event that no new and better information has become available.

- **Free ridership and spillover**. The savings that an efficiency measure produces in the home or business in which it is installed is commonly called its "gross savings". In contrast, "net savings" refers to the portion of gross savings that are attributable to a utility's efficiency program. It can adjust for the portion of savings that would have occurred anyway (e.g. because the customer would have installed the efficiency measure even without the utility rebate). Such effects are call free ridership. It can also adjust for the impacts a utility program has on the purchase and installation of efficiency measures that never get recorded by the utility (e.g. a customer is influenced by interaction with the utility to buy an efficiency measure but never claims a rebate). Such effects are called spillover effects.[2] The OEB requires that utilities adjust all of their savings to account for free rider effects. Though not required, it allows utilities to claim spillover effects provided that they are "supported by comprehensive and convincing empirical evidence, which clearly quantify the spillover effects that a specific program has had…"[3] To this point, the utilities have not made any such spillover claims. The conversion to net savings from gross savings is commonly called a "net-to-gross" (NTG) adjustment.
- **Custom Project Savings Verification (CPSV).** Every year the utilities hire engineering firms to critically review their estimates of savings for custom commercial and industrial efficiency projects. Custom projects often account for 80% of more of each utilities' total savings estimates. This process includes both a desk review of savings calculations and on-site visits to the facilities to verify that the measures were installed, take measurements of key efficiency or other operational parameters as appropriate, and discuss the project with the business. Only a sample of projects is reviewed. The CPSV firm's proposed changes to savings estimates for the sampled projects are then extrapolated – using what the evaluation industry calls "realization rates" – to the entire population of custom projects. This process has evolved over the years to the point where there is now in place a detailed sampling protocol (developed by an expert contractor hired by the TEC – see below) designed to provide 90% confidence that the extrapolation of savings adjustments to the

[2] Spillover can further be subdivided into three categories: (1) inside participant spillover which accounts for additional measures that a program participant installed at the same site as measures the utility rebated (or tracked and claimed as direct participant savings for other reasons); (2) outside participant spillover which accounts for saving that a program participant installs at a different site; and (3) non-participant spillover, which accounts for measures installed by customers who never directly participated in the utility's DSM programs in a way in which the utility would immediately know that savings had occurred.

[3] Ontario Energy Board, "Demand Side Management Guidelines for Natural Gas Utilities", EB-2008-0346, June 30, 2011.

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entire population of custom projects produces a total custom project savings estimate that is within 10% of what would have been found had every one of the (typically) hundreds of custom projects been separately reviewed.

- **Annual Reports**. The utilities are required to produce reports after the conclusion of each program year which document the savings achieved, as well as performance relative to other key metrics – particularly those metrics established for the purpose of (potentially) earning shareholder incentives. The results from the CPSV reports are incorporated into the annual report.
- **Annual Audit**. Each year an auditor is hired (separately for each utility) through the Audit Committee process (see below) to independently assess the reasonableness of the Company's claims regarding savings and other performance metrics addressed in its Annual Report. The auditor's report – included proposed adjustments to the utility's savings claim, its performance relative to other metrics of interest, its eligibility for shareholder incentives, its lost revenue adjustment and other factors – is required to be filed with the OEB by the end of June (i.e. within 6 months of the end of the year on which it is reporting).
- **Audit Committee (AC)**. The ACs' – which have been comprised of a utility representative and three elected stakeholder representatives – were originally created in 2000 to give stakeholders a voice in the hiring and input on the work of the independent auditors. However, their roles had gradually evolved to include providing some input on evaluation priorities, draft prescriptive measure savings characterizations and related items. With the filing of the utilities' 2012-2014 DSM plans, that portion of their role was shifted to the TEC (see below). In addition, their approach to decision-making – particularly in the selection of the annual auditor – was changed. In the past, though there was often consensus on the selection of the auditor, the utilities always had the final say. Under the new rules, the utilities and elected stakeholder reps continue to try to reach consensus on both a bidders list and on the ultimate selection of the auditor from among the firms who bid. However, in the event that consensus is not possible, the utilities get the final say on the bidders list – provided it has at least nine qualified firms on it – and the elected stakeholder reps have the final say on the selection of the auditor. This process is also communicated to all bidders, so that they realize that they are not just answering to the utility (to ensure that their work is truly independent).
- **Technical Evaluation Committee (TEC).** The TEC is to be comprised of a representative from each utility, three elected stakeholder representatives and two independent members who would be appointed by other five utility/stakeholder members. It is charged with developing gas DSM evaluation priorities for the province; developing scopes of work for new, high-priority province-wide evaluation projects; and hiring and overseeing evaluation

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contractors in the performance of that work. The TEC is designed to operate by consensus to the greatest extent possible, including in the selection of its independent members. Over the two years it has been in effect, the TEC has completed work on a sampling protocol for the CPSV process; reviewed and approved for submittal to the OEB a number of new measure savings (and other) assumptions as well as some changes to existing assumptions; and launched two major new evaluation projects – one to critically review all existing prescriptive assumptions and develop the provinces first, comprehensive, on-line Technical Reference Manual of such assumptions and another to assess free ridership and spillover for custom commercial and industrial projects. Both of the latter two evaluation projects are currently underway and expected to be completed in late 2014 or early 2015.

Comparison of Current Ontario Framework to Industry Best Practices

What follows is a brief assessment of how the current Ontario framework for performance measurement compares to best practices across North America. We focus particularly on the following items:

- Independence of evaluation
- Requirements for impact evaluation
- Net-to-gross (NTG) adjustments

Independence of Evaluation

It is always important that any evaluation of the impacts of DSM be independent of the entity charged with delivering energy savings and other forms of progress in markets for efficiency. It is particularly important when the entity charged with delivering results – the gas utilities in Ontario – has the ability to earn substantial financial incentives for meeting or exceeding goals – as is the case in Ontario. In the 1990s, it was standard practice to consider an evaluation to be "independent" if it was conducted by an independent third party, even if that party was chosen, managed and paid by the utility whose performance it was evaluating. However, that has changed over the past decade. Numerous jurisdictions now vest responsibility for evaluation - including setting evaluation priorities, establishing scopes of work for evaluations, selecting evaluation contractors and overseeing their work – with parties other than the utility or non-utility parties charged with delivering efficiency programs (the utility or non-utility program administrators have input into decisions, but someone else has the final say).

A variety of models for independent management of DSM evaluation are being used, with the decisions on details of the approach a function of the strength of existing institutions, capacity

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constraints, historic relationships and other local factors. Some jurisdictions, such as Vermont, vest the responsibility with a government agency (e.g. the Vermont Department of Public Service). Others vest it with regulatory staff. For example, staff of the Illinois Commerce Commission have veto power over the hiring of the utilities' evaluation contractors and exercise considerable influence over the design of evaluation studies. In yet another approach, the New Jersey Board of Public Utilities chooses to contract with the Rutgers University Center for Energy, Economic and Environmental Policy to manage the state's DSM evaluation work. Another model is used in the southern New England states of Massachusetts and Connecticut. In those states, the utilities have ceded responsibility for evaluation to councils comprised of state government agencies, consumer groups and environmental advocates. Typically, those councils have their own expert consultants which they hire with funds provided by the utilities. The consultants support council stakeholders in negotiating the utilities' DSM performance goals, help the council engage the utilities on ways to improve their programs and become the staff that oversee the DSM evaluation work.

To be sure, over the past 14 years the OEB has made significant strides in making gas DSM evaluation more independent as well. This began in 2000 with the requirement of annual independent audits of utility savings claims and the creation of audit committees to oversee those audits. However, until recently, the auditors were still ultimately under the control of the utilities. The utilities had the final say in who to hire. The also typically had much more interaction with the auditor, with audit committees being briefed much less frequently regarding key audit questions, likely leading to greater utility influence on the audit outcomes. In addition, the utilities retained complete control over decisions on how to spend evaluation budgets, the crafting of scopes of work for evaluation studies, the selection of evaluation contractors and the over-sight of their work. The only check on that control was having the auditors review the resulting reports. A significant additional improvement was made a couple of years ago when the TEC was created – giving stakeholders an equal voice in establishing evaluation priorities, hiring of evaluation contractors and overseeing the work of those contractors – and the changing of the rules for hiring of auditors – giving stakeholders final say in who to hire (keeping in mind that the utilities had final say in developing the bidders' list) in the event a hiring consensus decision (with the utility) was not possible. In addition, the audit committee members are also now invited to participate in all substantive discussions with the auditor.

Despite this significant progress, one substantial conflict with the concept of evaluation independence remains. Specifically, the utilities still have complete control over the hiring and oversight of the CPSV firms charged with evaluating the reasonableness of the companies'

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custom commercial and industrial efficiency projects – projects that typically produce the lion's share (often 80% or more) of their savings. To be sure, stakeholders – through the TEC – have input on the scope of work for the CPSV firms. As recently as this current year (e.g. the 2013 Enbridge audit), they also have received increased (relative to past years) ability to review and provide feedback on both the draft and final work products of the CPSV firms (in the previous year, stakeholder members of the AC were only able to review the final CPSV reports). The CPSV firms' work is also reviewed and critiqued by the annual auditor. However, the CPSV firms still know that they are hired and managed exclusively by the utilities. Their budgets are also set by the utilities.

Thus, one important process modification the OEB should make in its next gas DSM guidelines is to make the hiring and oversight of the work of the CPSV firms independent of the utilities. Perhaps the most logical way to do that within the existing Ontario evaluation structure – which appears to be functioning reasonably well otherwise – would be to have the Audit Committees hire the auditor earlier (i.e. late summer or early fall of the year whose results they will audit) and have the auditor hire and oversee the work of the CPSV firms. This would not require a significant increase in the work load of the auditor because they already do intensive reviews of the CPSV firms' work. Indeed, it might even reduce some aspects of the auditors' work load because they could shape the CPSV work at the outset, rather than trying to fix problems them find after the work has been completed. This approach should address the concerns about the thoroughness and independence of the custom commercial and industrial savings estimates that were recently raised before the OEB in proceedings regarding both Union's and Enbridge's 2012 shareholder incentive claims.

Requirements for impact evaluation

In most jurisdictions where there is substantial investment in DSM, there is an expectation – and often even a regulatory requirement – that all "resource acquisition" programs of any appreciable size will be subjected to a regular cycle of impact evaluations (typically ranging from annually to every three years, depending on the size of the program, expected variability of savings, cost of evaluation and other factors). Such evaluations are commonly used to update deemed savings values and/or to directly adjust utility estimates of program savings (as well as to inform future program design).

Historically, there has been less impact evaluation of the Ontario gas utilities' DSM programs than of comparable programs in other leading jurisdictions. Most of the impact evaluation that has taken place in Ontario has taken the form of either verification studies to determine whether measures were actually installed and stayed installed or, more recently, independent

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engineering assessments of the reasonableness of the companies' custom C&I project savings estimates. There has been very little direct measurement of actual savings – either for the purposes of adjusting deemed savings values for individual measures, for developing revised baseline assumptions for key technologies or for adjusting program-level savings estimates. To be sure, there have been exceptions. Enbridge's measurement of pre- and post-installation gas consumption to estimate the impacts of retrofitting low flow showerheads is a good example. However, such work has been the exception rather than the rule. There are some signs of improvement in recent years. For example, following a recommendation from a recent Enbridge auditor,[4] the recent CPSV terms of reference require on-site measurements whenever possible to augment "desk reviews" of custom project savings calculations. However, much needs to be done to "catch up" to the level of measurement that is performed in other jurisdictions.

Part of the problem is likely to be a function of inadequate budgeting for evaluation. A rough rule of thumb is that evaluation should consume between 3% and 6% of DSM budgets.[5] As noted above, in their 2012-2014 DSM plan, Enbridge Gas set aside 2.4% to 2.8% of their total budget for evaluation. Union Gas set aside 3.2%. Those are respectable budget levels – at least at the lower end of the range that would be ideal. However, it is important to note that evaluation spending in prior years was substantially lower. For example, in 2011, Union Gas spent only about $470,000 (or about 1.7%) of the approximately $28 million that it spend on DSM.[6]

All of this suggests that the Board should consider the following when developing the next set of guidelines for gas DSM in the province:

- Require that all programs undergo some form of impact evaluation at least once every three years;
- Require that, in addition to key verification activities, such impact evaluations include some form of measurement – whether whole facility billing analysis, end use metering, calibrated building simulation modeling, and/or other accepted methods;

[4] Energy & Resource Solutions, "Independent Audit of Enbridge Gas Distribution 2012 DSM Program Results", Final Report, June 26, 2013 and Energy & Resource Solutions, "Independent Audit of Enbridge Gas Distribution 2011 DSM Program Results", Final Report, June 27, 2012.
[5] State and Local Energy Efficiency Action Network, "Energy Efficiency Program Impact Evaluation Guide", prepared by Steven R. Schiller, Schiller Consulting, Inc., December 2012, www.seeaction.energy.gov
[6] Union Gas, "Final Audited Demand Side Management 2011 Annual Report", June 29, 2012.

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- Require that impact assessment of the very large custom C&I programs continue to be conducted through the CPSV process, but with increased emphasis on on-site measurement;
- Require a minimum of 3% of DSM budgets continue to be set aside for evaluation, with higher amounts to be encouraged if required in the short term to address key data uncertainties;
- Push back the deadline by which annual audit reports must be filed from the end of June to at least the end of July in order to facilitate more extensive field work by CPSV firms.

Net to Gross Adjustments

As noted above, the current OEB guidelines require that the utilities' gross savings be adjusted for free ridership; adjustments for spillover are permitted – with sufficient evidence – but not required. There are at least a couple of concerns with how this policy has been implemented to date.

First, there has been almost no direct evaluation of either free ridership or spillover for Ontario's gas DSM programs. As noted above, the TEC is currently managing a new study of such effects for Union's and Enbridge's custom commercial and industrial (C&I) programs. However, that study is just getting underway, so results are not likely to be available until late 2014 – more than six years after the only other study of free ridership and spillover for custom C&I programs.[7] Moreover, neither utility has sponsored and made public any other study of free ridership and/or spillover effects for any other market since then. Thus, most of the free ridership estimates currently being used are based on either professional judgment or studies from other jurisdictions, and most have not been changed in years. Put simply, there has been a significant under-investment in net-to-gross evaluation in the province.

Second, the approach to net-to-gross adjustments embodied in the OEB's current gas DSM guidelines leads to an inherently conservative estimate of DSM savings and cost-effectiveness. To be sure, this approach protects against utilities "chasing free riders" or attempting to claim inflated levels of spillover to meet goals, which could be a natural tendency absent such a protection, especially with the wide latitude given to the utilities to adjust the design of their programs as they see fit to meet goals[8] and the significant shareholder incentives at stake if those goals are met and/or exceeded. Such protection is important. However, the Board can

[7] Summit Blue Consulting, "Custom Projects Attribution Study", submitted to Union Gas and Enbridge Gas, October 31, 2008.
[8] This kind of flexibility is generally a "good thing" in that it allows utilities to adapt in real time to feedback from the market about which strategies to promote efficiency are working and which are not.

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retain that protection while producing more balanced estimates of savings by making clear that estimates of spillover that are based on independent studies of the Ontario utilities' programs, using industry accepted methods, will be accepted. The Board can also require that spillover be assessed as part of evaluation activities whenever the incremental accuracy in net savings is commensurate with the incremental cost of the spillover assessment.

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2014 OEB Gas DSM Framework Issue Paper:

Performance Incentives

Current Ontario Framework

In June 2011, the Ontario Energy Board (OEB) issued a new set of demand-side management (DSM) guidelines for the province's two gas utilities. Among the key issues those guidelines addressed was incentive payments "to encourage [the utilities] to aggressively pursue DSM savings and recognize exemplary performance" of the utilities' DSM programs.

The 2011 guidelines established a $9.5 million cap on the incentive for budgets of $28.1 million and $27.4 million for Enbridge and Union respectively, with the cap scaling in proportion to the budget. The incentive caps are thus set in the range of 34% to 35% of the budgets. The incentive caps are subdivided in proportion to the percentage of the budget for each of three program clusters (resource acquisition, low-income, and market transformation).

For resource acquisition and low-income programs, the OEB decided that the incentive should be based on the following metrics:

- Cubic meters (m^3) of cumulative natural gas saved;
- $ spent per m^3 of cumulative natural gas saved, as a measure of prevention of lost opportunities; and
- The number of participants that receive at least one deep measure, where "deep measures" are to be determined by a consensus process and "could include increase in insulation in more than half of the walls, basement walls, or the attic of the home."

For market-transformation programs, the OEB expressed a preference for the first two metrics above and "other outcome based metrics."

The OEB specified that the incentive structure for each metric would start at a level that the OEB describes as the 50% level (although it need not be 50% of the target level[9]), rising linearly to 40% of the cap at the target, and 100% of the cap at the 150% level. See Table 1: Savings Achieved and Shareholder Incentive Earned for a visual representation.

[9] For example, the OEB's 2011 DSM Guidelines for Natural Gas Utilities explains that "50%", "100%" and "150%" targets could be set at 40 units, 60 units and 70 units, respectively (p. 32). To clarify the concepts, subsequent settlements have seen the "50%/100%/150%" terminology replaced by the terms "lower band," "target", and "upper band" (for Union) and "lower," "middle," and "high" targets (for Enbridge).

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Table 1: Savings Achieved and Shareholder Incentive Earned

Savings Level	% of Shareholder Incentive Cap Earned
"150% level" (OEB) "High target" (Enbridge) "Upper band" (Union)	100%
"100% level" (OEB) "Middle target" (Enbridge) "Target" (Union)	40%
"50% level"(OEB) "Lower target" (Enbridge) "Lower band" (Union)	0%

Current Ontario Incentive Structures

Settlements among the stakeholders have refined the OEB's approach in several ways:

- The $ spent per m3 of gas saved incentive concept has not been used. This is wise. A low $/m3 may indicate good program management, or it may be a result of cream-skimming. A high program cost per m3 can indicate that the program is achieving deeper savings, or it can indicate poor management of contractors, over-paying for services, and paying higher incentives that necessary, all of which would use up budget that could better be used for additional installations. The OEB indicated that part of the motivation for this kind of metric would be to provide an inducement for utilities to maximize the effectiveness of their spending. However, that objective should already be sufficiently encouraged by combining sufficiently aggressive performance metrics, rigorous evaluation and budget constraints.
- Union split the resource acquisition category between industrial customers with opt-out options and other customers, and split the deep-savings metric for the latter between residential and non-residential customers.
- For the low-income programs, incentives are split between single- and multi-family m3, and Enbridge added a metric for the percentage of customers on the Low Income Building Performance Management (LIBPM) who enroll in the DSM program.

The Rationale for Incentives

Utilities often act as though their primary interest is in growing their rate base. Load growth requires installation of more mains, which increases rate base and total earnings, but also requires that the utility raise more capital, spreading those earnings over more shares. Increasing rate base will not benefit shareholders if the OEB sets the return on equity at a level

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that is just high enough to allow the utilities to attract capital. In that situation, increased investment would increase earnings but require the utility to raise more capital, and the existing shareholders would be no better off once the higher earnings are spread over both the existing and new shareholders. In the presence of an effective LRM, DSM would not harm LDC earnings per share.

If the OEB allows a return on equity higher than the actual cost of equity, shareholders would benefit from increasing rate base. For example, if new equity could be attracted with a return of about 8%, but the OEB allowed a 10% ROE[10], the DSM incentive would need to provide utility shareholders with an offsetting benefit equivalent to about 2% of the equity, times the avoided capital costs of LDC investments attributable to the DSM.

Since the Ontario LDCs have never acknowledged that any distribution capital projects are avoidable through DSM, let alone estimated the avoided investment, it is difficult to determine what incentive would be required to overcome the disincentive of the hypothetical lost-ROE windfall.

Other factors may also encourage the utilities to favor throughput over DSM. Management may benefit both financially and in less tangible ways from higher sales and investments. In addition, both Enbridge Gas Distribution and Union are affiliates of pipeline companies, which may be able to increase earnings by increasing pipeline throughput to their affiliated LDCs.

If, for any reason, the DSM incentives that are adequate in many leading jurisdictions are not sufficient to motivate effective DSM planning and implementation in Ontario, the OEB should consider alternatives, including moving responsibility for DSM to an independent entity, similar to those in Vermont, Nova Scotia, Oregon, and a handful of other North American jurisdictions.

Shareholder Incentive Levels

As a basic principal, utility shareholder incentives should be large enough to engage senior management, to attract good staff to work on DSM and to make (along with lost revenue adjustments and other policies) the pursuit of all cost-effective efficiency at least as profitable for the utility as not promoting efficiency would be. Of course, the incentives should also be no larger than necessary to accomplish those objectives. Needless to say, it is not always simple to determine exactly where that fine line is.

[10] Pollution Probe posited such a situation in EB-2002-0484, Pollution Probe Final Argument, p. 3.

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With those objectives in mind, it may be useful to benchmark the current Ontario gas incentives against those in place in other jurisdictions. One commonly used benchmark is the size of the incentives in comparison to DSM budgets. As Table 2 shows, the incentives offered to the Ontario gas utilities are at the high end of continent-wide practice for gas and electric DSM incentives using that benchmark.

Table 2: Energy-Efficiency Incentive Caps as Percent of Spending

Jurisdiction	Covered Program Administrators	Fuels	Incentive Cap as % of Budget
Arizona	APS		20%
Arkansas	All	Electric &Gas	7%
California	PG&E	Electric &Gas	10.1%
Colorado	Xcel, Black Hills	Electric	20%
Connecticut	All IOUs	Electric &Gas	8%
District of Columbia	DC Efficiency Utility	Electric &Gas	4.2%
Georgia			No cap
Kentucky	Duke, Kentucky Power		10%
Massachusetts	All IOUs	Electric &Gas	5.5%
Michigan	All IOUs	Electric &Gas	15%
Minnesota			30%
Nevada			5%
New Hampshire			12%
New York	All LDCs	Gas	2.3%
North Carolina	Duke		No cap
Ohio			15%
Oklahoma			15%
Rhode Island	National Grid	Electric	4.4%
Texas	All IOUs	Electric	20%
Vermont	Efficiency VT	Electric &Gas	4.1%

However, that benchmark is only relevant if the DSM budgets of the comparison jurisdictions are also comparable to those in Ontario. Put another way, a large percent of a small budget may be less effective in attracting management attention and offsetting lost earnings from supply-side investments than a smaller percent of a much larger budget. As demonstrated in TAF's paper on DSM budgets and goals, Ontario gas DSM spending in recent years has been much lower than spending in leading jurisdictions. Thus, as shown in Table 3, though the Ontario utilities' maximum shareholder incentive is more than twice that of the Michigan utilities and nearly ten times that of the Massachusetts' utilities when expressed as a percent of DSM budget, it is actually fairly similar to both jurisdictions when normalized to each

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jurisdiction's annual gas sales.[11] This suggests that shareholder incentives could be held to current levels, or perhaps increased only very modestly, even if future budgets and spending are increased fairly dramatically as the Savings Goal and Budget Setting paper suggests would be appropriate.

Table 3: Energy-Efficiency Gas Incentive Caps per Unit of Gas Sales

	Total Gas Sales (m3)	Gas Sales Reference Year	Total DSM Budget	Budget Reference Year	DSM Budget per m3 Sales	Max Utility Incentive $	Max Utility Incentive % of DSM Budget	Max Utility Incentive per 1000 m3 Sales
Ontario Utilities								
Enbridge	11,300,100,000	2012	$30,910,000	2012	$0.0027	$10,450,000	34%	$0.92
Union	14,617,390,000	2012	$30,910,000	2012	$0.0021	$10,450,000	34%	$0.71
Other Examples								
Massachusetts	6,319,346,456	2012	$191,766,032	2015	$0.0303	$6,930,855	4%	$1.10
Michigan	13,366,672,182	2012	$ 73,487,238	2013	$0.0055	$11,023,086	15%	$0.82

Types of Performance Metrics

The types and general structure of performance incentive metrics that the OEB promoted through its 2011 DSM Guidelines and that the utilities and other stakeholders refined through settlement negotiations and subsequent DSM plan filings are very good and consistent with best practice across North America. In particular, as in Ontario (for gas utilities) today:

- Leading jurisdictions typically have multiple performance metrics to address multiply policy objectives;
- Consistent with the point above, total energy savings, low income savings (and/or participation levels) and market transformation are objectives for which it is common to see specific, targeted performance metrics;
- The industry has begun to focus greater attention on total lifetime energy savings rather than just first year savings;
- Many leading jurisdictions establish a minimum level of performance below which no shareholder incentive is earned – that minimum level is typically in the range of 75% to 80% of budgeted goals;
- Many leading jurisdictions establish continuums between the minimum threshold required to earn any incentive, the budgeted goal levels and exemplary performance

[11] Comparisons to Massachusetts and Michigan are provided because anecdotal evidence suggests that utilities in both jurisdictions find their performance incentives to be substantial enough to have attracted management attention and interest.

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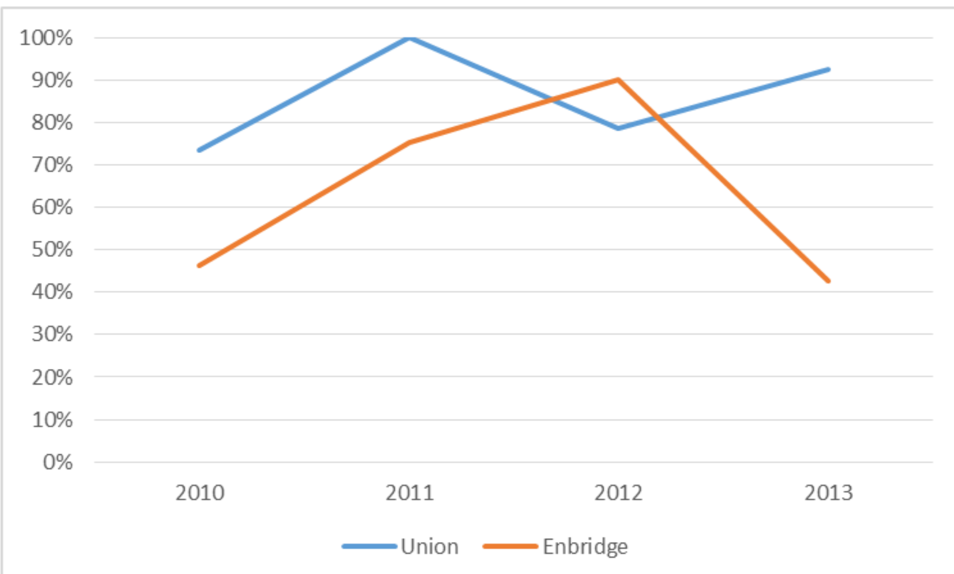
levels (often on the order of 115% to 125% of budgeted goals), with incentives increasing as performance improves along those continuums.

In general, utilities should only be earning the maximum incentives for performance that is truly exemplary. Put another way, incentive targets that the LDCs find easy to reach should move steadily upward. As Figure 1 shows, in recent years Union Gas has achieved or come close to achieving its maximum incentive most years. On the other hand, though Enbridge Gas has earned an incentive, its earnings have been lower – less than half of the maximum it has been eligible to earn in two of the past four years. These trends warrant careful examination to determine whether the differences are attributable to much better performance by Union or just to more aggressive goal-setting for Enbridge.

Figure 1: % of Maximum Incentive Earned By Union Gas and Enbridge Gas[12]



Computation of the Incentive Scorecards

In addition, as discussed below, there are some quirks in the way the 2011 DSM Guidelines established the "scorecard" approach to weighting the importance of different performance metrics that likely had unintended consequences and should be revisited.

[12] Values unadjusted for recent Board decisions on Union's 2011 results and Enbridge's 2012 results. 2013 values for Union are prior to any audit adjustments or possible OEB adjustments; 2013 values for Enbridge also are prior to any possible OEB adjustments.

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Incentive for uneven attention to metrics

Under the Board's 2011 Gas DSM Guidelines,

> No incentive will be provided for achieving a scorecard weighted score of less than 50%. …. Metric results below 50% will be interpolated using the 50% and 100% targets, metric results above 150% will be interpolated using the 100% and 150% targets[13].

In other words, each program group (scorecard) stands or fall on its own. If a utility misses the minimum incentive mark for a program group, it loses the opportunity to earn the portion of the incentive allocated to that program group; if it exceeds the performance required for the allocated incentive cap for the program group, it gets no incremental incentive for that group. However, individual program groups (scorecards) often contain multiple performance metrics. Under the existing guidelines, a utility can totally fail one metric, exceed the high target on another metric, and still get the maximum incentive for the program group.

The treatment of the metrics above the upper bands encourages the utilities to pile on resources for the metrics that prove easy to achieve and to neglect the metrics that are harder to achieve. This is particularly true where the increase in incentive per unit of performance above the middle target is larger than the decrease in incentive per unit of performance below the middle target.

Potential for unintended over-weighting of metrics

Under the current approach, the stakeholders may agree on a new metric, to encourage the utility to move in a new direction, but without any clear idea of how difficult that metric will be to achieve. Even if the incentive mechanism gives that metric a low weight, such as 5%, that single metric may turn out to be easy to exceed and the utility may exceed the metric several times over. The 5%-weighted metric can end up contributing 25% or more to the utility's achieving the overall scorecard target. This feature of the weighting greatly reduces the meaningfulness of the metric weights, and can easily distract the utility from metrics that are given higher nominal weights towards relatively minor metrics on which the utility finds it can run up the score.

[13] OEB, 2011, DSM Guidelines for Natural Gas Distributors, p. 32.

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Inconsistent distinctions between program groups

The distinctions between the program groups and the metrics are not consistent or logical. For example, in the 2013 Draft Evaluation Report, Enbridge treats three metrics for the low-income programs (single- and multi-family m^3 and LIBPM participation) as a single program group, but splits the six metrics in the market transformation programs into four smaller program groups. While the over-performance on low-income single-family m^3 and LIBPM are able to offset some of the under-performance on low-income multi-family m^3, the over-performance on drain-water heat recovery and commercial Savings By Design (SBD) cannot offset any under-performance on other market transformation metrics. The over-performance on the number of realtors committed to home labelling can offset the shortfall in ratings performed (since they are both part of the home-labeling component), but not the failure to earn the maximum incentive for the residential SBD program.

Recommendation

The incentives would be more consistent and effective if each metric were allocated a portion of the incentive cap, without any opportunity for performance above the high target or upper band to offset any failure to meet the high target for other metrics. This is already the case for Enbridge's incentives for drain-water heat recovery and commercial SBD and Union's incentives for Large Industrial scorecard. That approach should be extended to the other metrics.

Additional and Modified Metrics

Deep Savings

Some of the metrics for deep savings do not appear to represent very deep savings, such as Union's 2012 commercial/industrial target of 5.5% average savings. Deep-savings incentives should be directed to increasing penetration of truly deep savings, such as reductions of more than 30% in existing buildings and construction of new buildings to 20% below the requirements under existing codes and standards.

Since deep savings for a particular non-residential facility or multi-family building can take a few years of sequenced improvements, providing incentives for truly deep savings may require that the metric be defined over a longer period than one year. For example, the metric might count the m^3 saved in buildings that have saved 30% or more over the previous five years.

Lost Opportunities

More fundamentally, the incentive scheme should restore a form of the Board's lost-opportunity metric, based on after-the-fact independent evaluation of whether programs are encouraging participants to go as far as is cost-effective (i.e., maximizing inches of attic insulation, furnace AFUE or window U value) or achieving substantial increases in market shares for key efficiency technologies or practices (e.g. Energy Star-certified new homes).

Geo-targeting

Finally, the Board should consider, where appropriate and relevant, introducing a geo-targeting metric to reward the utilities for identifying and relieving areas that will otherwise require transmission and distribution reinforcement. In the recent GTA transmission cases, it was revealed that Enbridge has long known of emerging load-related capacity constraints on its transmission system, which would require hundreds of millions of dollars for the GTA projects in segment B, and $10–$20 million annually in load-related reinforcements in parts of the GTA, but had not reflected any of those savings opportunities in DSM planning. A geo-targeting metric should consist of an external evaluation of the utility's process for identifying potential reinforcement requirements over the next decade, designing enhanced DSM efforts to avoid those reinforcements, and implementing those enhancements.

Conclusions

Recent trends in the gas utilities' incentive earnings should be examined to determine whether incentive thresholds are set at appropriate levels, and to ensure that utilities are only earning the maximum incentives for truly exemplary performance. Comparison with other North American jurisdictions suggests that incentive levels in Ontario should be held to current levels or increased only very modestly even if utilities' DSM budgets increase dramatically. Existing performance incentive metrics are generally consistent with best practice across North America, but could be made more effective if each performance metric were allocated a portion of the incentive cap, if incentives encouraging deep savings were more appropriately targeted, and if metrics to encourage geo-targeting and avoidance of lost opportunities were introduced or reintroduced.

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This brief has been prepared for TAF by Paul Chernick, Resource Insight, and Chris Neme, Energy Futures Group, with research support from TAF Policy Researcher, Rebecca Mallinson. Please treat this material as 'draft' as elements may evolve during the course of discussions and in the formulation of input to the formal OEB consultation. Please note that the views and ideas expressed in these briefs are presented by the Toronto Atmospheric Fund to support the discussion around developing a new gas DSM policy framework. We welcome your views about these or other issues related to natural gas conservation policy in Ontario.

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2014 OEB Gas DSM Framework Issue Paper:

Gas-Electric Integration

On March 31, 2014, the Ontario Energy Minister issued a directive that the OEB establish a gas DSM framework that will enable the province's regulated gas utilities to acquire all cost-effective energy efficiency resources. The directive also states that the new framework should ensure that the gas utilities, where appropriate, "coordinate and integrate" their efficiency programs with the electric programs offered by both the Ontario Power Authority (OPA) and local distribution companies. This paper addresses opportunities for and ways the OEB could foster greater coordination and integration. Note that though the directive focuses solely on gas-electric DSM coordination, this paper looks at the issue a little more broadly, including consideration of opportunities for greater coordination between the province's two gas utilities.

Defining Coordination and Integration

Any discussion of DSM program coordination and integration must start with clarity about what those two terms mean. For the purpose of this paper, "coordination" is taken to mean that, at a minimum, there is consistency in the design of the program. That should include:

- Identical definitions of "efficiency" – i.e. the same level of efficiency, relative to baseline efficiency levels, is promoted province-wide,
- Consistency in program marketing/messaging to trade allies and consumers,
- Identical training curricula (where applicable),
- Identical quality assurance standards,
- Rebate (or other financial incentive) offerings that are designed with both gas and electric contributions in mind (i.e. sufficient *in combination* across fuels to induce significant customer participation)
- Consistent rebate (or other financial incentive) levels across the province (i.e. identical for all electric utilities and identical for all gas utilities), and
- Identical metrics of success (for market transformation programs).

For the purpose of this paper, "integration" is taken to mean joint delivery. That is, though each participating utility may have its own internal program administration, all program delivery services – whether training of trade allies, program marketing, direct installation of efficiency measures, quality assurance inspections or reviews, rebate processing, etc. – are provided by a single entity operating on behalf of two or more utilities. That is commonly accomplished by hiring one or more firms, which multiple utilities jointly select, to deliver program services. The work of those firms can be either managed jointly or by a single utility designed or chosen by the group (sometimes with different utilities taking the lead on different programs as a way to share efforts). However, it could theoretically also be accomplished by a single utility providing such services and then "billing" the collaborating utilities for their portion of the costs. In the end, the key attributes of integrated or jointly delivered programs are:

- A single, identical, consistent program design across fuels and geography;
- A single set of marketing materials (typically jointly branded);
- A single customer application for participation (e.g. a single rebate form);
- A single point of contact for customers and trade allies;
- A process in place for cost-sharing across participating utilities; and
- A process in place for joint program management and decision-making.

As described above, coordinated and integrated programs are two ends of a continuum for multi-utility DSM program collaboration. There can obviously be points in between as well. Specifically, it is possible to have a coordinated program of which only parts are jointly delivered (and parts are individually delivered).

Rationale for Greater DSM Program Coordination and Integration

There are a variety of potential benefits from greater coordination and/or integration of DSM efforts between utilities (and/or non-utility program administrators). These are summarized in Table 1 below.

Table 1: Potential Benefits of Coordinated and/or Integrated DSM Programs

Issue	Benefits	Gas-Gas Benefits	Gas-Electric Benefits
Program Costs	Integrated/Joint delivery of programs across utilities can lower overhead costs – e.g. costs for training, marketing, quality assurance and some administration – by reducing redundancy and spreading fixed costs across a greater volume of savings. An added benefit for gas-electric integration is the ability to share rebate (or other financial incentive) costs.	Yes (some)	Yes (more)

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Enhanced Reach	Both coordinated and integrated/joint programs targeting the same efficiency products or services can enable engagement of trade allies, manufacturers or others that might otherwise have not been possible. It can even enable the delivery of a program that might not have otherwise been possible. This is partly related to the program cost savings noted above, and partly a function of the critical mass that is sometimes necessary to effectively engage trade allies.	Yes	Yes
Market Clarity	Both coordinated and integrated/joint programs should result in more consistent messages about the efficiency products and services consumers should buy, the benefits of those products and services, where and how they can be acquired, etc. Conversely, uncoordinated programs that promote different efficiency levels to the same customers (gas and electric) and/or to retailers, vendors, contractors, builders, etc. who work with customers in different service territories can create market confusion. Greater market clarity typically leads to greater program participation and, therefore, greater savings per dollar spent.	Yes	Yes
Lower Transaction Costs for Consumers	Integrated/joint programs are typically easier for customers to access because there are fewer forms to complete, fewer program staff with which to interact, fewer site visits by program staff required, etc. As a result, they typically result in greater program participation and, therefore, greater savings per dollar spent.	In some cases (e.g. chains or national accounts)	Yes
Greater Prospects for Market Transformation	Almost by definition, long term market transformation requires the kind of consistency in program design, messaging and delivery that comes from at least coordinated programs if not integrated/joint programs.	Yes	Yes

Of course, there are also some costs to coordinating and/or integrating the delivery of programs. In particular, extra time and effort is required by utility staff to reach out to other utility staff and negotiate details of program design, delivery and/or management. Depending on the nature of the working relationships, it can also be more difficult to make quick changes to programs in response to market feedback. Such costs tend to be highest initially, but then decline as utilities develop trust and systems for working together. In general, most DSM experts believe that benefits outweigh the costs, at least for certain types of programs (see below).

When DSM Program Coordination and/or Integration Should Be Pursued

There are almost always advantages to at least coordinating, if not integrating, delivery of DSM programs, both across multiple gas utilities and between gas and electric utilities. However, it is more important for some types of programs than for others. It is particularly critical for the following four types of programs:

- **Market Transformation Programs.** Transforming markets requires either changing social norms at the consumer level; changing norms of manufacturers, vendors, retailers, contractors, builders and/or other key trade ally groups; and/or facilitating the adoption of new government regulations (codes and standards) which, in turn, typically requires enough of a change in the market (e.g. a substantial enough market share for a product) so that the government is not perceived as being too far ahead of the curve. Changing social norms or the norms of trade allies or government regulations is not easy and typically requires clear, consistent and uniform efforts and messaging. Moreover, many key trade allies (e.g. manufacturers, large builders, large distributors, etc.) require assurance that they will have a sufficiently large market for a new product or service before they will consider changing their behavior and business plans. That typically necessitates having all parties in a particular jurisdiction – and sometimes even across multiple jurisdictions – promoting the same efficiency product or service in the same way.
- **Mass Market Programs**. For products that are sold in relatively large numbers – usually to residential and/or small commercial customers – it is important that DSM programs make the transactions for retailers, contractors, vendors and other trade allies, many of whom serve customers in multiple utility service territories, as easy and simple as possible. This is important for several reasons. First, the profit per product is often too small to make the transaction costs of dealing with multiple programs worthwhile. Second, the individuals selling the products often do not have the capacity to understand and convey to customers multiple program offerings. Third, sales people cannot always easily determine which utility serves the customer with which they are currently interacting, making them less willing to work with multiple different programs. In addition, sales staff for retailers and many other trade allies often turn over quickly, making it even more challenging to ensure multiple messages for different utility customers are conveyed appropriately.
- **Multi-Measure/Whole Building ("Deep Energy") Retrofits**. When examining whole buildings for energy-saving retrofit potential, assessments should include all fuels used by the building. Pursuing multiple measures to save both gas and electricity (and water)

can yield greater savings, greater GHG reductions, and provide a building owner with a shorter payback and better return on investment than pursuing gas-saving measures alone. Coordinating gas and electric program delivery can facilitate a building-focused (rather than measure-focused) approach to improving energy efficiency, and can exploit synergies between gas and electric measures that enable deeper savings than would be possible if measures were pursued in isolation.

- **Would-be Stranded Opportunities.** In the same vein, some retrofit programs cannot be justified by the savings for just one fuel. For instance, it can be challenging for an electric utility to run a program targeted to a gas-dominated market where electricity users are the minority – there simply may not be enough electric savings available to justify the fixed costs of running a program. However, a gas utility running a DSM program in the same market has no incentive to capture cost-effective electric savings. In such cases, it is important for gas and electric utilities to collaborate on program design and delivery so that the greatest "bang for the buck" across all fuels can be realized.

Challenges to Coordinating and/or Integrating Programs

There are certainly challenges to coordinating and/or integrating efficiency programs. Chief among these are figuring out how to work together. However, experience in numerous jurisdictions – including Vermont, Massachusetts, Connecticut, Illinois, California and others – clearly demonstrates that these obstacles can be overcome.

A variety of approaches to working together have been successfully tested. Where multiple utilities (rather than just two) are involved, it is common to have regular, structured meetings – initially to work out the design of programs, but just as importantly to manage those joint programs as they are delivered and refined. One example that has been in place since the 1990s is the Massachusetts Joint Management Committee (JMC) in which the state's several electric and several gas utilities have managed a statewide residential new construction program through a number of evolutions over time. A variety of other examples are cataloged in a forthcoming ACEEE publication on combined gas and electric efficiency programs (expected publication is August 2014).

As one might expect, often one of the trickier aspects of working together is developing a protocol for how to share costs of jointly delivered programs. Several different approaches have been used in different jurisdictions. Perhaps the fairest is:

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- to require each utility to pay for the financial incentive offered for any measures that save only that utility's fuel (this applies to both joint delivery between multiple gas utilities, between multiple electric utilities and/or between gas and electric utilities);
- to allocate the cost of other measures that save multiple fuels in proportion to the net present value of the electric and gas benefits (this applies only to joint delivery between gas and electric utilities); and
- to allocate non-measure costs such as marketing, training, quality assurance, evaluation and jointly funded administration, in proportion to the net present value of the benefits of the program as a whole to each participating utility (this applies to both joint delivery between multiple gas utilities, between multiple electric utilities and/or between gas and electric utilities).

This approach is currently being used in northern Illinois (the Chicago area) in collaboration between Commonwealth Edison (the electric utility) and Nicor Gas, People's Gas and North Shore Gas. It has been used in other jurisdictions as well.

One disadvantage to this approach is that it can require periodic adjustments to cost allocations when there are changes in avoided costs (which in turn lead to changes in the distributions of benefits). However, that appears to have been eminently manageable in the jurisdictions where this approach has been used.

Of course, there are also other, simpler ways to allocate common costs, including allocations based on site energy savings (expressing electric and gas savings in a common format, such as joules), based on source energy savings or based on even simpler negotiated fixed percentages.

Coordination and/or Integration in Ontario

One might expect that coordination and integration would be a little more challenging in Ontario than in other jurisdictions for a couple of reasons. First, there are more than 70 electric distribution companies with which the province's gas utilities would potentially need to work. Second, the OEB does not have quite the same level of oversight authority over the Ontario Power Authority's DSM programs as it does over the province's gas programs[14]. However, those challenges do not fully explain the fairly limited degree of cross-utility collaboration to date.

[14] Though it should be noted that the OEB reviews the OPA's administrative budget and the potential economies of scope and scale associated with gas-electric collaboration should inform that review. Further, the OPA should be amenable to coordination or integration given the explicit government policy in the directive to the OEB.

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First, it is worth emphasizing that greater coordination and integration of Enbridge Gas and Union Gas DSM efforts – i.e. gas-gas collaboration – should be comparatively easy. However, it has been fairly limited to date. To be sure, the creation of the province-wide Technical Evaluation Committee (TEC), in which both gas utilities are working together with stakeholders to jointly develop evaluation priorities and jointly manage province-wide evaluation studies, is a positive step forward. However, more can and should be done. For example, it is worth noting that though both utilities have residential new construction market transformation programs in the 2012-2014 plans, the two programs are substantially different. Enbridge is working with builders on integrated design processes to achieve 25% savings relative to the current Ontario building code while Union is promoting the construction of new homes that are 15% more efficient than the code. Needless to say, it will be harder to transform the market when two different efficiency standards are being promoted! In its next gas DSM guidelines, the OEB should require that the two gas utilities have, at a minimum, the same market transformation programs. They should also be required to collaborate on the design and, where cost-efficient, joint delivery of mass market programs targeted to residential and small business customers (i.e. on the sale and purchase of efficient products sold to those customers).

With respect to gas-electric collaboration, while the existence of more than 70 LDCs theoretically makes collaboration potentially very challenging, the reality is likely less complicated. First, the five largest electric LDCs account for about 60% of electricity sales in the province.[15] Moreover, most of the electric efficiency programs run in the province originate with the Ontario Power Authority (OPA). Thus, the OEB could require that the gas utilities endeavor to reach agreement with the OPA and at least the largest electric LDCs on common program designs and, where cost efficient and/or necessary to avoid creation of lost opportunities, joint delivery of parts of all of those programs. That said, collaboration should not be required at all costs. If the price of collaboration would be standards that are too low, rigidity in the face of quickly changing market conditions or other adverse impacts, the affected utilities should be expected to back away from collaboration.

In sum, at a minimum, the gas utilities should be required to document in their plans the program areas in which they succeeded in collaborating or attempted to collaborate with electric DSM efforts and, where efforts to collaborate ultimately failed, to explain why. Put another way, there should be a burden imposed on the gas utilities to demonstrate that the failure to collaborate on programs which could potentially benefit from collaboration was in

[15] Ontario Energy Board, 2012 Yearbook of Electricity Distributors, August 22, 2013 (http://www.ontarioenergyboard.ca/oeb/_Documents/RRR/2012_Electricity_Yearbook_excel.xls).

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rate-payers best interests. The Board and other parties will need to accept that there will be some subjectivity to make such determinations. Of course, the OEB should also use all means at its disposal to encourage the OPA and the electric LDCs to pursue productive collaboration with the gas utilities whenever possible.

Fuel-Switching – Another Aspect of Integration

The discussion above focused exclusively on multi-utility collaboration on the design of efficiency programs. One additional, related, gas-electric integration topic that merits consideration is fuel-switching. Fuel-switching is not very common in most utility efficiency program portfolios, in large part because utilities often resist measures that shift load to another fuel. However, depending on the circumstances, such shifts can be economically cost-effective, environmentally beneficial and result in lower total energy use (the ultimate definition of efficiency).

The current OEB Gas DSM framework appropriately allows the gas utilities to pursue fuel-switching away from gas as part of their DSM efforts as long as the fuel-switching is economic and leads to a net reduction in greenhouse gas emissions. To date, that option has received very little attention.[16] However, it may merit much greater attention in the future for a couple of reasons.

First, studies in both California[17] and Europe[18] suggest that the most likely path to meeting long-term carbon emission reduction requirements includes substantial electrification of building space heating, water heating and other end uses (as well as cars), coupled with the de-carbonization of the electric grid and massive investments in cost-effective energy efficiency.

Second, recent advances in both the efficiency of electric heat pumps and their ability to function effectively in cold climates, has brought that technology to the point where it could be (or at least could become) competitive with natural gas heating alternatives, depending on local energy prices.[19] For example, cold climate ductless heat pumps currently produced by

[16] Enbridge Gas has supported fuel-switching to ground source heat pumps in a couple of commercial building new construction projects.
[17] Energy and Environmental Economics, Inc., *Meeting California's Long-Term Greenhouse Gas Reduction Goals,* November 2009.
[18] European Climate Foundation, *Roadmap 2050, A Practical Guide to a Prosperous, Low-Carbon Europe,* April 2010 http://www.roadmap2050.eu/
[19] If the local price for electricity is $0.14/kWh, the average 2013 Ontario price for consumption of about 1000 kWh per month (http://www.ontario-hydro.com/index.php?page=electricity_rates_by_province), then a heat pump with an efficiency of 280% to 300% will produce heat at the same cost as an 80% efficient gas furnace system (including distribution losses) using gas that costs $0.39 to $0.42/m^3 – not much higher than the current marginal

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Mitsubishi and Fujitsu can maintain their nameplate capacity down to -15˚ C (whereas air source heat pumps of the past cold not operate without inefficient electric resistance back-up much below freezing) and still produce heat below -25˚ C (though at reduced capacity). Though the efficiency of these systems does decline as temperatures fall, recent field tests in central New Hampshire[20] and Idaho[21] – locations with winter conditions similar to if not colder than Toronto – suggest that one can expect an average seasonal efficiency of 280% to 300%. In other words, if one is using electricity produced by a gas turbine with an efficiency of 45% and losing 10% of that power through transmission and distribution system losses, the net source efficiency of the heat provided is 113%[22] - well above what is possible with the best gas furnace (i.e. ~98%, even assuming no distribution losses). If nothing else, the new cold climate heat pumps ought to be very carefully considered as an efficiency improvement in buildings using electric resistance heat, particularly if the building owners are considering the alternative of switching to gas heat.

On the other hand, combined heat and power (CHP) systems have the potential to consume slightly more gas but less total energy to meet heat and power needs than if the customer relied on the central electric grid for power and a separate gas boiler for space heating.

In short, given both long-term climate policy imperatives and economics – i.e. what is cost-effective – the OEB should begin to require greater consideration of fuel-switching. In particular:

- any efficiency potential studies – gas and electric – should be required to explicitly examine fuel-switching options to determine when they are cost-effective;
- utilities should be encourage to pursue fuel-switching away from their fuel whenever it is cost-effective and reduces greenhouse gas emissions;

cost of gas to residential customers in the province. Of course, one must also consider forecasts of how electric and gas prices will change in the future, the costs of the heating systems themselves, whether a gas hook-up is required (with its attendant costs) and other factors. However, the bottom line is that heat pump technology has advanced to the point where this analysis has become necessary.

[20] Energy & Resource Solutions, *Emerging Technology Program Primary Research – Ductless Heat Pumps*, prepared for the Northeast Energy Efficiency Partnerships, May 2014 (http://www.neep.org/Assets/uploads/files/emv/emv-library/NEEP%20DHP%20Report%20Final%205-28-14%20and%20Appendices.pdf).

[21] Baylon, Dave et al. (Ecotope, Inc.), *Ductless Heat Pump Impact & Process Evaluation: Field Metering Report*, prepared for the Northwest Energy Efficiency Alliance, Report #E12-237, May 1, 2012 (http://neea.org/docs/reports/ductless-heat-pump-impact-process-evaluation-field-metering-report.pdf?sfvrsn=16). See, in particular, results for the two Idaho locations.

[22] $0.45 * 0.90 * 2.80 = 1.13$

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- utilities should be precluded from subsidizing conversions to their fuel (whether through DSM or non-DSM means) unless they can demonstrate that such conversions are cost effective and reduce greenhouse gas emissions.

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2014 OEB Gas DSM Framework Issue Paper:

Are Ontario Gas Utilities' Efficiency Programs Worth It?

Across Canada, the United States and beyond, electric and gas utilities are running programs to help homeowners and businesses invest in energy efficiency. Those programs typically include rebates or other financial incentives to buy different efficiency products and services, as well as efforts to educate consumers on their benefits. The programs are typically funded by all of the utilities' customers through small charges on their monthly electric and/or gas bills or built into their rates.

In Ontario, both Enbridge Gas and Union Gas have run such programs since the 1990s. Together, they currently spend roughly $70 to $80 million per year,[23] but are still capturing only a modest portion of the cost-effective gas efficiency potential in the province. The Ontario Energy Minister recently instructed the Ontario Energy Board (OEB) to establish a new regulatory framework that would result in the province's gas utilities acquiring all cost-effective energy efficiency. A healthy debate is currently underway among various stakeholders and within the OEB about what that means and how to accomplish it.

It is important to note that the OEB – like similar regulators in other provinces and states – has always required that the utilities' energy efficiency programs be cost-effective – i.e. that the dollar savings over the life of the efficiency improvements are greater than the costs of the programs. Assessments of cost-effectiveness are based on determinations of the components of current energy bills that can be avoided (and which cannot) by using less energy, on forecasts of future energy prices, on assumptions about how to discount the value of benefits that accrue in the future, and on a variety of other assumptions. Those sophisticated approaches to assessing cost-effectiveness may be appropriate for regulators and others who are involved in the arcane nuances of these issues, but can be difficult for the average consumer to understand. The following attempts to distill the key aspects of the cost-effectiveness of the gas utilities' conservation programs to date, and what that suggests about the design of the new policy framework and future programs.

[23] This includes the cost of incentives the utility shareholders can earn if the utilities do a good job and meet or exceed energy savings targets and/or other related goals.

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Utility Efficiency Program Costs

The simplest way to look at the cost of utility-run efficiency programs is to compare how much the utility spent per unit of energy saved, over the life of the savings (recognizing that many efficiency measures, such as insulating a home, will save gas for many years). The Ontario results for 2012 are as follows:

- Enbridge Gas' energy efficiency programs cost an average of just \$0.06 per m^3 of gas saved.[24]
- Union Gas' programs cost even less – an average of just \$0.03 per m^3 of gas saved – mainly because it has more large industrial customers for which efficiency savings are usually less expensive.
- The average customer currently pays on the order of \$0.30 to \$0.35 per m^3 consumed, even after one excludes the fixed monthly charge.

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

Total Economic Value to the Province

A more complex way to look at whether utility-funded efficiency programs make economic sense is to compare the total cost of the programs – both what the utilities spent, plus what their customers spent on the efficiency measures[25] – to the value of the savings.

Historically, the Ontario utilities have taken a very conservative approach to estimating the economic value of efficiency. They have counted all the costs, but only a portion of the benefits – mostly just the value of the gas fuel, and the value of electricity and water savings (many efficiency measures that save gas, such as insulating buildings or installing low-flow showerheads, also save electricity or water).

They have traditionally ignored the value of reduced investment in new pipelines; the value of reduced environmental emissions; the benefits of lowering gas prices;[26] and value of improved comfort, improved business productivity and other non-energy benefits to its customers.

[24] This is the "levelized cost" of gas saved. It takes Enbridge's total spending on its efficiency programs, plus the payments its shareholders received for doing a good job, and spreads them out over the roughly 18 years that the savings from its efficiency programs will last on average, just like the purchase price of a house is translated to a monthly payment for a mortgage, to account for the fact that the spending occurs once but the savings recur (with related bill savings) for many years.

[25] For example, if an efficiency measure costs \$100 and the utility provides a \$30 rebate, the customer must pay the other \$70. In this analysis of the net economic value of efficiency programs, both of those components of the efficiency costs are included.

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Nevertheless, even using the utilities' very conservative estimates of the benefits of efficiency, their 2012 programs were extremely cost-effective.

- Union Gas estimated that its customers will realize over $310 million in gas, electric and water bill savings (mostly gas) for a *total cost* of about $80 million (*total cost* includes the $31 million cost of Union's programs, plus the added expenditures customers make themselves). From just one year of running its efficiency programs, Union and its customers produced over $230 million in net savings to consumers.
- Enbridge's estimates of the economic benefits of its 2012 efficiency programs are not currently publicly available. However, in its plan for that year it estimated it would achieve approximately $150 million in customer bill savings (again, mostly gas, but some electricity and water too) at a *total cost* of about $42 million (*total cost* includes the $31 million cost of Enbridge's programs, plus the added expenditures customers make themselves). Thus, from one year of running its programs, Enbridge estimated it would produce $108 million in net savings to consumers.[27]
- Ontario consumers are saving in the order of $338 million (net), with utility investment of just $62 million.

Economic Development Benefits

Investment in efficiency tends to be more labor intensive and more local than spending on gas which is imported from distant provinces and/or states. Thus, local insulation companies and vendors of other efficient products can add jobs as a result of these programs.

In addition, the cost savings discussed above have rippling effects through the provincial economy:

- Lower bills mean businesses are more competitive with business in other jurisdictions, protecting and potentially supporting expansion of jobs.
- Lower bills for business can also mean lower prices for some products for Ontario customers.
- Lower bills mean customers have more disposable income to spend on other products, often purchased from local stores, restaurants and/or other service providers. That, in turn, helps protect or even add jobs to the economy.

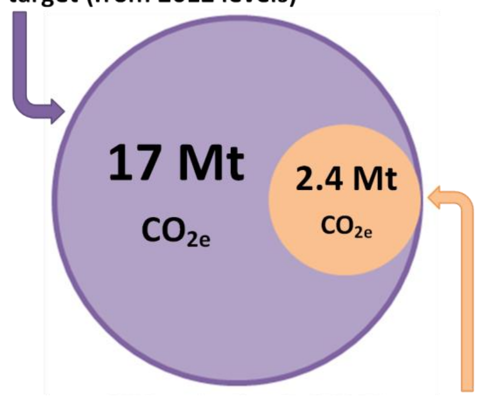
[26] The basic law of supply and demand says that when demand goes down, prices go down – even if only a little.
[27] This is likely an under-estimate of the actual net economic benefits since Enbridge reported significantly exceeding its savings targets for the year.

Put simply, cost-effective efficiency programs are one of the best ways to spur local economic development.

Environmental Benefits Too

The 25 billion cubic meters of natural gas used annually in Ontario are directly responsible for almost 50 million tonnes of greenhouse gas emissions, which is about 30% of the province's emissions.

- The gas efficiency measures the two Ontario gas utilities' programs caused to be installed in 2012 will reduce carbon dioxide emissions by 6.4 million tons.[28] That is equivalent to taking 1.75 million cars – or nearly one-quarter of Ontario's cars and light trucks – off the road for a year.[29]
- Reducing natural gas use by just 1% per year starting in 2015 would lower Ontario's 2020 GHG emissions by 2.4 megatonnes – that represents about 15% of the distance from Ontario's 2012 emissions to 2020 GHG target.



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[28] Estimate is based on the reduction in carbon dioxide emissions associated with the efficiency measures installed as a result of the utilities' resource acquisition programs (over the expected life of the savings). It is conservative in that it does not account for energy savings from the utilities' market transformation programs, the emission reductions associated with the electricity savings the utilities' efficiency programs also produce, or the methane emissions (methane is a more potent greenhouse gas than carbon dioxide) associated with producing and distributing natural gas.
[29] Based on NRCAN estimates of emissions per liter of gasoline and 2009 estimates of the average liters of gas used per 100 km, the average km driven annually and the number of vehicles on the road in Ontario.

STATEMENT
PUTTING A PRICE ON CARBON
JUNE 3, 2014

Climate change poses one of the greatest global challenges and threatens to roll back decades of development and prosperity.

The latest report from the United Nations Intergovernmental Panel on Climate Change makes clear the importance of putting a price on carbon to help limit the increase in global mean temperature to two degrees Celsius above pre-industrial levels.

Depending on each country's different circumstances and priorities, various instruments can be used to price carbon to efficiently and cost effectively reduce emissions, such as domestic emissions trading systems, carbon taxes, use of a social cost of carbon and/or payments for emission reductions.

Governments are taking action. In 2014, about 40 national and over 20 sub-national jurisdictions have already implemented or scheduled emissions trading schemes or carbon taxes. Together, these jurisdictions account for more than 22 percent of global emissions. Many more countries and jurisdictions are advancing preparation for pricing carbon. Together, these represent almost half of global GHG emissions.

Corporations are responding. A growing number of companies are already working within carbon pricing systems and are developing expertise in managing their emissions. Others are incorporating greenhouse gas reduction targets in their business planning. In 2013, over 100 companies worldwide publicly disclosed to CDP that they already use carbon pricing as a tool to manage the risks and opportunities to their current operations and future profitability. Businesses see that carbon pricing is the most efficient and cost effective means of reducing emissions, leading them to voice support for carbon pricing.

The momentum is growing. Pricing carbon is inevitable if we are to produce a package of effective and cost-efficient policies to support scaled up mitigation.

Greater international cooperation is essential. Governments pledge to work with each other and companies pledge to work with governments towards the long-term objective of a carbon price applied throughout the global economy by:

- strengthening carbon pricing policies to redirect investment commensurate with the scale of the climate challenge;
- bringing forward and strengthening the implementation of existing carbon pricing policies to better manage investment risks and opportunities;
- enhancing cooperation to share information, expertise and lessons learned on developing and implementing carbon pricing through various "readiness" platforms.

We invite all countries, companies and other stakeholders to join this growing coalition of the working.