Ontario Energy Board

Ontario

EB-2008-0346

Staff Discussion Paper

On Revised Draft Demand Side Management Guidelines for Natural Gas Utilities

January 21, 2011

This page has been left blank intentionally

Table of Contents

1. Overview and Background

The Ontario Energy Board (the "Board") established the original regulatory framework for natural gas utility sponsored demand side management ("DSM") programs through guidelines set out in its E.B.O. 169-III Report of the Board dated July 23, 1993. Union Gas Limited ("Union") and Enbridge Gas Distribution Inc. ("Enbridge") filed DSM plans in accordance with the E.B.O. 169-III Report until 2006. Natural Resource Gas Limited ("NRG") has not filed any DSM plans with the Board.

In 2006, the Board conducted a generic proceeding to address a number of issues related to natural gas utility DSM activities (EB-2006-0021). The Board's Decisions in this proceeding, which form the basis of what is referred to throughout this document as "the current DSM framework," were issued in three phases:

- The Phase I Decision, issued on August 25, 2006, dealt with a large number of issues relating to DSM and set out a framework for a multi-year DSM plan;
- The Phase II Decision, dated October 18, 2006, approved the input assumptions for Union and Enbridge's DSM plans; and
- The Phase III Decisions, released January 26, 2007 and April 30, 2007, approved Union and Enbridge's respective three-year DSM plans (i.e., for 2007, 2008 and 2009).

In anticipation of the expiry of both Enbridge and Union's DSM plans at the end of 2009, the Board initiated a consultation process in October 2008 to review the current DSM framework and establish through guidelines a revised DSM framework to be used by natural gas utilities in developing their next generation of DSM plans (EB-2008-0346). The first step in this consultation process was meetings with natural gas utilities and interested stakeholders representing ratepayer and environmental interests. The meetings took place on November 24 and 26, 2008. They were led by Board staff and provided an opportunity for the exchange of preliminary views on the issues forming part of this consultation.

On January 26, 2009, the Board issued its initial draft DSM guidelines for comment along with a Board staff discussion paper. On February 6, 2009, the Board also issued a draft report on "Measures and Assumptions for Demand Side Management (DSM) Planning" prepared by Navigant Consulting Inc. ("Navigant") for stakeholder comment.

On February 23, 2009, Bill 150, *An Act to enact the Green Energy Act, 2009, and to Build a Green Economy, to repeal the Energy Conservation Leadership Act, 2006 and the Energy Efficiency Act and to Amend Other Statutes*, ("the Green Energy Act") was introduced. On April 14, 2009, the Board issued a letter advising natural gas utilities that due to uncertainties relating to the Green

Energy Act, it would not require the development of a new multi-year DSM framework for natural gas utilities. Instead, the Board required Enbridge and Union to file one year DSM plans for 2010 under the current DSM Framework. The Board's intention was that a one-year period would provide time for the impacts of the Green Energy Act to become clear. On April 29, 2009, the Board issued the final report prepared by Navigant Consulting Inc., which set out the input assumptions that natural gas utilities should use for the development of their 2010 DSM Plans.

On May 13, 2009, the Board issued a letter advising natural gas utilities that DSM programs targeted to low-income energy consumers would be considered separately from other DSM programs. More specifically, the Board indicated that the Low-Income Energy Assistance Program Conservation Working Group ("CWG") would establish the DSM framework for programs targeted to low-income consumers. Natural gas utilities would then have to submit their DSM programs for low-income consumers based on the resulting Board-approved low-income DSM framework. The CWG submitted its final report on a proposed short-term framework for natural gas low-income DSM on August 13, 2009 (the "CWG Report").

By letter dated September 8, 2009, the Minister of Energy and Infrastructure[1] (the "Minister") advised the Board of the government's plan to develop a province-wide integrated program for low-income energy consumers, and requested that the Board not proceed to implement new support programs for low-income energy consumers in advance of a ministerial direction.

On September 28, 2009, the Board issued a letter along with the CWG Report advising of the Board's new approach on this consultation in light of the Minister's letter. The letter also directed the Enbridge and Union to submit their low-income plans for 2010 based on an extension of the current DSM framework.

By letter dated January 7, 2010, the Board directed Enbridge and Union to develop and file their DSM plans for 2011 based on the current DSM framework. In addition, the letter informed stakeholders that the Board would proceed with a review of the current DSM framework and that it had retained the services of two consultants. Concentric Energy Advisors ("CEA") was retained to prepare a report that evaluates Ontario's DSM framework against best practices in selected North American and other jurisdictions. Pacific Economics Group Research ("PEG") was also retained to assess the potential use of normalized average usage per customer for estimating the impact of the DSM programs.

[1] The Ontario Ministry of Energy and Infrastructure was separated into two ministries on August 18, 2010: the Ministry of Energy and the Ministry of Infrastructure.

The CEA and PEG reports[2] were posted for written comment on March 19, 2010. A stakeholder meeting on the CEA report was held on April 29, 2010 and a webinar on the PEG report was held on May 13, 2010. On June 7, 2010, written comments from 17 stakeholder groups were received, with the vast majority of those comments directed at the CEA report.

On July 5, 2010, the Board received a letter from the Minister informing the Board that it should now resume its work in relation to low-income energy customers. The Minister also indicated his support for the expansion of "DSM efforts in general".

[2] *Review of Demand Side Management (DSM) Framework for Natural Gas Distributors*, Concentric Energy Advisors, March 19, 2010 and *"Top Down" Estimation of DSM Program Impacts on Natural Gas Usage*, Pacific Economics Group Research, February 2010.

This page has been left blank intentionally

2. Purpose

The purpose of this Staff Discussion Paper is to provide background information, options and explanations for the recommendations on the major areas of the proposed Revised Draft DSM Guidelines, as shown in Appendix A.

This page has been left blank intentionally

3. Revised Draft DSM Guidelines

The proposed Revised Draft DSM Guidelines have benefited from the extensive participants' comments received since the beginning of this consultation in October 2008. Board staff has considered all participants' comments in developing the Revised Draft DSM Guidelines. This Staff Discussion Paper makes reference to participant comments to the extent necessary, but does not contain an exhaustive description of those comments. Participants' written comments are available on the Board's website.

The proposed Revised Draft DSM Guidelines also take into account existing policies and regulatory requirements regarding natural gas DSM activities. In addition, an attempt has been made to maintain consistency, where appropriate, of certain elements of the proposed natural gas DSM framework with the Ontario electricity Conservation and Demand Management ("CDM") framework. In particular, staff has been informed by the results of the Ontario Power Authority's ("OPA") consultations on the 2011-2014 province-wide electricity CDM programs as well as the recent Board consultations on electricity CDM.[3]

This Staff Discussion Paper makes a number of specific references to Enbridge and Union's natural gas DSM experience. However, this Staff Discussion Paper and the Revised Draft DSM Guidelines are meant to apply to all rate-regulated natural gas utilities, including NRG.

The Revised Draft DSM Guidelines are attached as Appendix A to this Staff Discussion Paper. The major areas addressed in the Revised Draft DSM Guidelines are discussed in this Staff Discussion Paper. Those major areas are:

1. DSM Framework;
2. Term of the plan;
3. Program types and design;
4. Screening;
5. Development, updating and use of assumptions;
6. Adjustment factors for screening and result evaluation;
7. Budgets;
8. Metrics
9. Targets;
10. Incentive payments;
11. Lost revenue adjustment mechanism;
12. Program evaluation and audit;
13. Filing and reporting requirements;

[3] Ontario Energy Board consultations on a Conservation and Demand Management Code for Electricity Distributors (EB-2010-0215) and on Electricity Conservation and Demand Management Targets (EB-2010-0216).

14. Stakeholder input and consultation process; and
15. Coordination and Integration of natural gas and electricity conservation programs.

3.1 DSM Framework

CEA noted that "the DSM framework in Ontario could be enhanced, but we do not believe that the current framework should be abandoned and replaced by something entirely different."

Most participants supported approaches that would build upon the current DSM framework instead of replacing it with a fundamentally different framework. However, three participants, respectively representing environmental, ratepayer and energy retailer interests, recommended that the Board consider using a centralized administrator approach, arguing that cost efficiency could be gained. Two of these participants also submitted that DSM programs are not inherently a natural monopoly function and that the current DSM framework does not provide a level playing field for other market participants. Another participant representing ratepayer interests submitted that funding of the Ontario government's energy efficiency and carbon emission reduction objectives is a matter for determination by the government; it should not be done through regulation of natural gas distribution rates.

In staff's view, no new significant evidence has been provided on the appropriateness or lack thereof of the natural gas utilities undertaking DSM activities as part of their regulated business. In light of the participants' generally supportive comments to build upon the current DSM framework, staff is of the view that consideration of a fundamentally different framework is not warranted at this time.

With regard to the potential use of normalized average usage per customer for estimating the impact of the DSM programs that PEG investigated, participants unanimously agreed with the PEG report's conclusion that the existing "bottom-up" approach should continue to be employed. While two participants indicated that further research in that area may be worthwhile, other participants generally expressed the view that the Board should not spend any more resources on investigating or improving upon a "top-down" approach. Based on the findings of the PEG report and the comments received, staff is not proposing to incorporate a "top-down" approach as part of the Revised Draft DSM Guidelines.

3.2 Term of the Plan

Some participants commented on the length of the multi-year plan, with proposals including terms ranging from 3 to 5 years. Staff notes that longer terms provide additional regulatory and funding certainty to support long-term DSM planning. However, staff also notes that the benefits of a longer term plan need to be balanced with the need to review the framework on a frequent enough basis to respond to the changing regulatory and public policy environment. Accordingly, staff proposes a term of three years. Staff notes that the proposed three-year term, which would end in December 2014, would coincide with the established timeline for electricity distributors' CDM targets.

Staff proposes that the Board consider a review of the natural gas DSM framework during the three-year plan term. If the Board is satisfied that the natural gas DSM framework remains appropriate, the Board could extend its term.

3.3 Program Types and Design

The current DSM framework allows for three generic types of programs: resource acquisition, market transformation and low-income programs.[4] The current DSM framework also allows for the approval of research and development ("R&D") and pilot programs, based on a case-by-case basis review.

The Enbridge and Union recommended introducing a new generic type of DSM program called "development programs." Two other participants, one representing environmental interests and the other ratepayer interests, provided comments supporting development initiatives. Union indicated that development programs may include "partnerships with Ontario universities and colleges, the training of delivery partners, contractors, and builders, as well as strategic consultation with delivery channels or assistance to government-supported codes and standards development." Enbridge described development activities to be "on the 'supply side' of energy efficiency." Enbridge also provided the following examples:

> <u>Capacity Building</u>: Training of building operators, building simulation technologists, residential renovators and homebuilders;
>
> <u>Infrastructure Development</u>: Working with municipalities to explore opportunities through district energy systems that capture waste heat from one part of the community and transfer it to another sector;

[4] These programs are described in more details in the Revised Draft DSM Guidelines.

> Research and Development: Partnerships with [Natural Resources Canada], [Canada Mortgage and Housing Corporation], and others to develop the next generation of energy efficient construction and new energy efficiency technologies.[5]

Staff is of the view that the three current generic types of DSM programs, in addition to the possibility of funding for pilot programs, covers an adequate spectrum of DSM activities for the natural gas utilities to undertake. Staff notes that some of the examples provided by Enbridge indicate that part of those programs may fall within market transformation and pilot programs, such as the “Infrastructure Development” and “Research and Development” programs. It may also be that some “infrastructure development” programs could be considered custom resource acquisition projects.

While staff notes that the proposed “Capacity Building” described by the natural gas utilities may not be fully captured by the current generic types of DSM programs, staff is not convinced that it should be within the purview of the rate-regulated natural gas utility DSM portfolio as stand-alone programs. Nonetheless, staff notes that it may be that resource acquisition and low-income programs require a certain level of “Capacity Building,” which may be part of a program delivery component.

3.3.1 Program and Portfolio Design

Participants commented on guiding objectives to design DSM programs and the overall portfolio. Staff supports four principles which were broadly accepted by participants. Namely, the DSM portfolio should include programs that balance the following objectives:

- Maximization of cost effective natural gas savings;
- Provision of equitable access to DSM programs among and across all rate classes to the extent reasonable, including access to low-income customers;
- Prevention of lost opportunities[6]; and
- Pursuit of deep energy savings.[7]

In staff’s view, those guiding principles taken together with the proposed overarching DSM framework (e.g., screening, metrics, incentives, stakeholder engagement, etc.) will generally provide the extent to which guidance from the

---

[5] Enbridge’s written comments, June 7, 2010, p. 11.

[6] Lost opportunity markets refer to DSM opportunities that, if not undertaken during the current planning period, will no longer be available or will be substantially more expensive to implement in a subsequent planning period.

[7] Deep energy savings refer to measures that result in long-term savings, such as thermal envelope improvements (e.g., wall and attic insulation).

Board on "design" is warranted. While a number of participants proposed specific program design elements to be part of the new DSM framework, staff is of the view that they should more aptly be considered by the natural gas utilities through their respective stakeholder engagement processes before filing their multi-year DSM plans with the Board. This would ensure greater flexibility in DSM program and portfolio design, recognizing that the natural gas utilities are ultimately responsible and accountable for their actions.

Flexibility is a cornerstone of staff's proposal. Using updated input assumptions to calculate the incentive amounts – which in staff's view will provide an incentive for natural gas utilities to continuously react to, adapt to and anticipate market developments – requires a flexible DSM framework with regard to program design and prioritization. Staff is also of the view, however, that some of this flexibility needs to be monitored.

Accordingly, staff proposes to adopt provisions similar to those introduced in Section 3.2 of the Board's electricity CDM Code. Namely, natural gas utilities would not be required to apply for Board approval unless cumulative fund transfers among Board-approved DSM programs exceed 30% of the approved annual DSM budget for an individual natural gas DSM program. The natural gas utilities would also be required to seek approval to re-allocate funds to new programs that are not part of the natural gas utility's Board-approved DSM plan. In staff's view, these filing requirements will help ensure that an appropriate balance among the four overarching guiding principles is maintained and that the proposal is consistent with the other elements of the new DSM framework.

3.3.2 Low-Income Programs

The purpose of DSM programs tailored to low-income consumers is to recognize that although they may result in lower TRC net savings than similar non-low-income DSM programs, they also result in various other benefits that are difficult to quantify.[8] Those programs also more adequately address the challenges involved in providing DSM programs for and special needs of this consumer segment.

Staff notes that low-income programs do not truly constitute a different type of generic natural gas DSM programs, but are rather a set of resource acquisition and market transformation programs designed for and targeting low-income customers. Hence, the distinctive features of low-income programs result from additional guiding principles and design characteristics, as opposed to the nature of the programs per se.

[8] These various benefits not captured by the traditional net TRC savings measure may include reduction in arrears management costs, increased home comfort, improved safety and health of residents, avoided homelessness and dislocation, and reductions in school dropouts from low-income families.

Three participants supported adopting the guiding principles in the CWG Report, two recommended using the principles advised by CEA[9], and a few other participants recommended other guiding principles.

In staff view's, the long-term guiding principles laid out in the CWG Report represent the most relevant basis since they represent the consensus views of a representative group of interested participants. Staff also recommends including Principle 4 and 5 c) of the CWG Report for which a majority of the CWG agreed, with one dissenting view expressed in each case. Principle 4 refers to the provision of "integrated, coordinated delivery, wherever possible, with electricity [Local Distribution Companies ("LDC")] and natural gas utilities" as well as with other entities. Principle 5 c) refers to "capture potential lost opportunities for energy savings, including new construction of low-income/affordable housing." Staff notes that the participants' comments were broadly supportive or consistent with Principles 4 and 5 c).

Staff notes that Principle 3 indicated that low-income customers should be eligible for the low-income DSM programs "whether or not these residents are responsible for paying their energy bills." For consistency with the OPA's definition of an eligible "low-income customer" as further explained below, staff proposes taking out this wording from Principle 3.

The proposed guiding principles are therefore that low-income natural gas DSM programs should:

1. Be accessible to low-income natural gas consumers;
   a) Be accessible province-wide in the long term;
   b) Require no upfront cost to the low-income energy consumer and result in an improvement in energy efficiency within the consumer's residence;
   c) Address non-financial barriers (e.g. communication, cultural and linguistic).

2. Be delivered in a cost-effective manner;

[9] CEA's recommended guiding principles are "First, the utility should identify geographic regions with the highest concentration of low-income customers. Second, the utility should primarily focus on those customers with the highest energy use and those who have a history of late payments or face disconnection. Third, in order to capture economies of scale, the utility should develop programs that serve an entire neighborhood, rather than an individual customer. Fourth, the utility should concentrate on DSM programs that provide immediate and long-term benefits, such as home weatherization and appliance replacement. Fifth, the utility should coordinate with community organizations and local contractors to modify consumer attitudes and behaviors through education. Finally, the utility should understand that serving the low-income or disabled population requires a grassroots, community-based effort." *Review of Demand Side Management (DSM) for Natural Gas Distributors*, Concentric Energy Advisors, Inc., March 19, 2010, p. 84.

3. Provide a simple, non-duplicative, integrated and coordinated application, screening and intake process for the low-income conservation program that covers all segments of the low-income housing market including, for example, homeowners, owners and occupants of social and assisted housing, and owners of privately owned buildings that have low-income residents;
   a) Use criteria for determining program eligibility.

4. Provide integrated, coordinated delivery, wherever possible, with electric LDCs and natural gas utilities; provincial and municipal agencies; social service agencies and agencies concerned with health and safety issues;
   a) Encourage collaboration with partners such as private, public and not-for-profit organizations for program delivery.

5. Be a direct install program;
   a) Provide a turnkey solution from the perspective of the participant such that the participant deals with one entity for the program which coordinates all elements of delivery;
   b) Emphasize deep measures that may include, where applicable, energy efficiency, demand response, fuel-switching, customer based generation and renewables;
   c) Capture potential lost opportunities for energy savings, including new construction of low-income/affordable housing.

6. Provide an education and training strategy;
   a) Encourage behaviour change of program participants toward a culture of conservation;
   b) Help low-income energy consumers help themselves;
   c) Help program participants to understand the benefits of participating in the low-income DSM program and conservation, in general;
   d) Help channel partners attain necessary skills.

7. Provide on-going measurement of results, feedback and accountability for continuous improvement of the program and identification of best practices;
   a) Design programs that encourage persistence of energy savings.

8. Ensure that incentives for utilities are adequate for success;

9. Have a DSM framework that strikes an appropriate balance between having a stable framework and having the flexibility to respond to changing market conditions;
   a) Be comprised of multi-year programs;
   b) Allow for appropriate capacity building within the natural gas utilities and in the marketplace.

To facilitate coordination between low-income electricity CDM and natural gas DSM programs, staff recommends using the same definition of a “low-income consumer" to be used in the OPA's Province-Wide program, as shown in the box below.

Low-Income Natural Gas DSM Program Eligibility

As further described below, there are four criteria for participant eligibility that consumers must meet to participate in low-income natural gas DSM programs: 1) income eligibility; 2) utility bill payment responsibility 3) building eligibility and 4) landlord consent (where applicable). It will be the responsibility of the natural gas utility, through their agent responsible for low-income program eligibility screening, to confirm participant eligibility.

Income Eligibility Criterion

The low-income natural gas DSM program income eligibility criterion requires meeting at least one of the following four criteria:

1. Household Income at or below 135% of the most recent Statistics Canada pre-tax Low-Income Cut-Offs ("LICO") for communities of 500,000 or more, as updated from time to time;

2. Primary or secondary name on utility bill is a recipient of one of the following social benefits:

   a) The National Child Benefit Supplement;
   b) Allowance for the Survivor;
   c) Guaranteed Income Supplement;
   d) Allowance for Seniors;
   e) Ontario Works; or
   f) Ontario Disability Support Program.

3. All social and assisted housing units (as defined below) are eligible for low-income natural gas DSM programs. Eligibility criteria for social housing residents will be reviewed by the agent responsible for low-income program eligibility screening and a complex-wide eligibility waiver/approval will be issued if eligibility criteria are consistent with income criteria used for the program. The natural gas utilities will use their discretion to implement this policy in order to ensure that social housing residents that participate in the program would otherwise be eligible under income eligibility criteria; or

4. Any household that resides in a community that is targeted for the neighbourhood blitz treatment (for example, neighbourhoods in which greater than or equal to 40% of households qualify according to the LICO thresholds established for the program) will be eligible for basic low-income natural gas DSM measures; these homes must meet at least one of the other income

criteria described above to qualify for deep DSM measures.

The natural gas utilities through their agent responsible for low-income program eligibility screening must ensure that all participants (with the exception of social and assisted housing residents) provide proof of income in the form of a copy of their last income tax assessment or social benefit statement. The agent responsible for low-income program eligibility screening must verify that this proof meets the income criteria outlined above. The natural gas utilities (or its delegate) will be responsible for obtaining a landlord waiver form in which the landlord will acknowledge and consent to the implementation of program measures and treatments in participating homes where applicable.

Utility Bill Payment Responsibility Criterion

Participants must pay their own utility bill, except where they reside in social and assisted housing. All residents of social and assisted housing (in Part 9 buildings, as defined by the Ontario Building Code ("OBC")) will be eligible for participation in the program provided they meet all other eligibility requirements. Only natural gas-heated homes will be eligible for building envelope measures.

Building Eligibility Criterion

Consumers must be residents of single family low-rise buildings (more fully defined by Part 9 of the OBC as residential buildings of three stories or less with a footprint of less than 600 square metres), as well as mobile homes. Residents of privately-owned buildings defined by Part 3 of the OBC that pay their own utility bill will not be eligible for deep or building envelope improvement measures, but will nonetheless be eligible for other in-suite low-income natural gas DSM measures provided that their landlord consents to their participation in the program.

Landlord Consent Criterion (if applicable)

1. Private Building Residents:
   a) Tenants living in privately rented homes must obtain the consent of their landlord to participate in the program.

2. Social and Assisted Housing Residents:
   a) Providers of social and assisted housing (as defined below) will be the first point of contact for social and assisted housing residents and must provide their consent for residents of their buildings to participate in the program.
      i) Once a social and assisted housing provider has agreed to participate, their residents will be invited to participate in the program (i.e., to determine if equipment that the resident owns qualifies for replacement);

ii) If a social and assisted housing resident identifies themselves to the program, the natural gas utility (or its delegates) will either direct the resident to contact their housing provider, or the natural gas utility (or its delegates) will contact the housing provider and encourage them to participate.

Definition of Social & Assisted Housing

For the purpose of the low-income natural gas DSM programs, social and assisted housing means residential social housing including all non-profit housing developed, acquired or operated under a federal, provincial or municipally funded program including shelters and hostels.

Examples of residential social housing are:

- Non-profit corporations as outlined in the *Social Housing Reform Act, 2000*;
- Public housing corporations owned by municipalities directly or through Local Housing Corporations;
- Non-profit housing co-operatives as defined in the *Co-operative Corporations Act, 1990*;
- Non-profit housing corporations that manage/own rural and native residential housing;
- Non-profit housing corporations that manage/own residential buildings developed under the Affordable Housing Program; and
- Non-profit organizations or municipal/provincial governments that manage/own residential supportive housing, shelters and hostels.

Staff notes that these proposed eligibility criteria for low-income natural gas DSM programs differ from those used for emergency financial assistance.[10] Staff notes that the main purpose of having DSM programs tailored to a group of low-income customers is to address barriers that could otherwise prevent those customers from being able to access DSM programs. In staff's view, limiting access to low-income DSM programs to the sub-set of low-income customers requiring emergency financial assistance would not be consistent with the purpose of low-income DSM programs. Staff is of the view that eligibility criteria that would generally allow for a broader group of low-income customers, such as those proposed above, would be more appropriate.

Staff notes that the CWG report acknowledged that low-income customer eligibility criteria for low-income DSM and emergency financial assistance need not be the same. More specifically, the CWG report indicated that the "These [program eligibility] criteria are for the low-income energy conservation program

[10] The eligibility criteria for emergency financial assistance, as proposed by the Financial Assistance Working Group and supported by the Board, are outlined in *the 2011 LEAP Emergency Financial Assistance Program Manual* dated November 2010.

and do not apply to the low-income emergency financial assistance program or any other program."

3.4 Screening

CEA proposed in its report to screen programs amenable to a mechanistic test using a societal cost ("SC") test instead of the current total resource cost ("TRC") test. The TRC test sums the stream of expected future resource benefits and costs over the life of the DSM measure(s) or technology(ies) from a DSM program or portfolio of DSM programs and uses a discount rate to express those streams as a single "current year" value. If the net present value is positive, or the benefit to cost ratio exceeds 1.0, then the DSM measure, program or portfolio is considered cost effective from a societal perspective. In addition to all costs and benefits considered in the TRC test, SC test takes into consideration externalities such as greenhouse gas emissions.[11]

Many participants noted that the measurement of externalities to derive the SC test would result in added complexities when compared to the TRC test. To overcome these complexities, one of these participants proposed that, instead of directly measuring externalities, an adjustment factor could be applied to the TRC test results as is done in some other jurisdictions (e.g., 1.05 in Colorado and 1.075 in Iowa).

Two participants representing ratepayers supported the continued used of the TRC test, with one indicating that the SC test may become more appropriate at some point in the future. In contrast, most participants either supported – such as the two natural gas utilities – or did not oppose the use of an SC test where feasible. However, a number of those participants expressed limiting complexities as a condition for their support to incorporate a broader range of benefits into the test.

Staff agrees that the estimation and inclusion of a broader range of benefits into the test could result in complexities. Staff is of the view that a modified TRC test approach can provide an appropriate balance between the desire to reflect certain externalities without unduly increasing the complexity of the screening test. The modified TRC test staff proposes would only add one external benefit to the current TRC test: a value for reduction in greenhouse gases ("GHG") emissions as measured in tonnes (1,000 kg) of carbon dioxide equivalent emissions ("CO_2e"). A discussion on how to determine the value of reduced CO_2e emissions is provided in section 3.5.2.2.

[11] For a description of a number of tests used to screen DSM programs, please refer to pp. 38-41 of the March 19, 2010 Concentric Energy Advisors' report entitled "Review of Demand Side Management (DSM) Framework for Natural Gas Distributors."

3.4.1 Screening Level

Participants were divided on the issue of whether the screening should be applied at the program or portfolio level, with one participant supporting a combined approach. CEA noted in its report that it believes that screening at the portfolio level "tends to blur the distinction between more effective programs and less effective programs, and it limits the flexibility of the Board to approve specific DSM programs as new technologies emerge and as policy objectives change." One participant stated that screening at the program level may result in the natural gas utilities bundling their less cost effective programs with more cost effective ones, which would lead to larger programs. This participant noted that larger DSM programs may be difficult to administer or for the affected customer groups to understand. This participant argued that screening should be performed at the portfolio level instead and that this would provide the natural gas utilities flexibility with new technology and program designs without leading to larger DSM programs.

Staff is of the view that screening should serve to remove from further consideration programs that are not cost effective, as determined by the screening test. While screening at the portfolio level may allow flexibility in terms of allowing for the inclusion of less cost effective programs, in staff's view this flexibility is not warranted to the extent that it allows programs that are not cost effective to be selected by the natural gas utilities. Accordingly, staff recommends performing screening at the program level. However, and as discussed below, staff recognizes the need for flexibility in screening certain types of programs, such as low-income customer programs, R&D and pilot programs and market transformation programs which may not be amenable to such a mechanistic screening test.

Staff notes that some multi-year programs may involve an initial ramp-up in the first year(s). Accordingly, when screening such a program on an annual basis, the lifetime benefits of the measures installed in the first year of the program may not outweigh the costs associated with that program's first year. Two participants representing environmental interests recommended that the screening test be applied on a multi-year basis as opposed to an annual basis.

Staff agrees that for programs that last for more than one year and for which there may be an initial ramp-up in the first year, a multi-year approach to screening is appropriate. Otherwise, such programs, which may result in net benefits over their entire life, but not necessarily so in their first year, would end up being screened out.

3.4.2 Screening of Low-Income Programs

CEA recommended using a lower threshold for programs directed to low-income customers (“low-income programs”) than the 1.0 threshold used for programs directed at other customers. CEA noted in its report that “Low-income consumers represent a significant proportion of potential conservation benefits, both in terms of quantifiable reductions in natural gas consumption, and in social benefits (such as increased health and comfort) that are extremely difficult to quantify.” Based on a SC test and informed by its jurisdictional review, CEA recommended a threshold range of 0.60 to 0.75 for low-income programs.

Most participants proposed, and none objected to, a screening methodology tailored to low-income programs. Most of these proposals supported using a threshold lower than 1.0 for the screening test; one participant representing low-income customers recommended to instead use a scorecard approach as explained below, while another participant also representing low-income customers supported either of these two approaches. One participant proposed using both a threshold for low-income programs and an overall minimum portfolio threshold of 1.0 or higher for all residential programs (i.e., including low-income programs). Another proposal was to use the approach outlined in the CWG Report.[12]

Staff notes that a scorecard approach can provide flexibility in screening programs by considering multiple metrics, as opposed to screening programs based only on an economic metric such as is the case with the TRC test. For example, a minimum weighted score of multiple metrics could be established (e.g., level of cost effectiveness, depth of savings, numbers of customers to be reached, total expected natural gas savings, etc.) with programs failing to meet the minimum weighted score being screened out. However, staff notes that this screening flexibility can result in complexities that outweigh its benefits, especially at the program screening stage.

Staff is of the view that clear and simple guidance on low-income program screening would be of benefit to the natural gas utilities and stakeholders. Accordingly, staff proposes to use a lower threshold for the modified TRC test instead of a scorecard approach.

CEA’s proposed range of 0.60 to 0.75 was based on an SC test, which was intended to incorporate benefits from additional externalities than would be the case under the modified TRC test proposed by staff. In staff’s view, it would therefore be appropriate to use a threshold at least somewhat lower than the upper end of this range. At the same time, staff notes that if the selected threshold is too low, the screening test may only screen out a limited number of

[12] Staff is unclear as to what this proposal entails given that there was no consensus on screening in that report.

programs and defeat to some extent the purpose of undertaking the screening in the first place. On balance, staff is of the view that a threshold of 0.70 would be reasonable. Staff notes that Enbridge and Union's requests for additional low-income DSM funding for 2011 are based on a TRC threshold of 0.70.[13]

3.4.3 Market Transformation Programs

Four participants commented that market transformation programs should be assessed on their own merits based on the specific objectives of the program. Staff agrees.

3.4.4 Research & Development ("R&D") and Pilot Programs

Two participants representing environmental interests and one representing ratepayers supported the introduction of special funding for R&D and for pilot programs as recommended by CEA. One of these participants proposed that R&D funding should be prioritized based on expected savings while another participant proposed using a lower screening test threshold.

In staff's view, funding for R&D and pilots is not amenable to a mechanistic screening approach and should be assessed on its own merits. As the need for these types of projects may change over time, staff is of the view that, instead of a dedicated fund, any funding for R&D and pilots should be part of the total DSM budget. Under this proposal, any spending in a year on R&D and pilots would reduce the amount available for other DSM programs in that year. The natural gas utilities will be expected to identify as part of their multi-year plan application the budgeted amounts for potential R&D and pilots based on their needs for developing and testing new technologies and programs.

3.4.5 Prioritization

CEA recommended that to the extent that not all candidate programs that have passed the screening test can be undertaken due to budget constraints, programs should be prioritized using the Program Administrator Cost ("PAC")

---

[13] See Enbridge's application dated November 11, 2010 and Union's application dated November 10, 2010 to amend their respective low-income weatherization plan within their approved 2011 DSM plans (Board file number EB-2010-0175 and EB-2010-0055, respectively). Staff notes that the 0.70 threshold proposed in these applications are based on different discount factors (10% for Union and 9.14% for Enbridge) than the discount rate proposed by staff in section 3.5.2.3. Staff also notes that the gas utilities' proposed 0.70 TRC threshold does not incorporate a value for greenhouse gases, whereas staff's proposal does. Accordingly, the 0.70 threshold included in the gas utilities' November 2010 applications is not directly comparable to the 0.70 threshold proposed by staff for the new gas DSM framework.

test. Except for two participants who supported CEA's recommendation, comments received indicated that the PAC test should only be used as one input when prioritizing programs or not used at all. One participant recommended using the participant cost test instead while another participant representing environmental interests suggested that the Board should require the ramp-up of the "levels of effort," possibly over a few years, to ensure the pursuit of all cost-effective savings.

In staff's view, it is clear that the iterative nature of DSM portfolio design and the various considerations participants highlighted require a more flexible approach to prioritization of DSM programs than using the PAC test alone. For example, some participants noted the need to balance the objective of maximizing cost-effective natural gas savings and providing equitable access to DSM programs among and across all rate classes. Staff notes that the stakeholder engagement process (see section 3.14) provide an opportunity for stakeholders to guide the overall prioritization process. Moreover, the proposed Revised Draft DSM Guidelines offer an overarching guiding influence over the prioritization process through the metrics, targets, and the incentive structure (see sections 3.8, 3.9 and 3.10). Consequently, staff recommends that the natural gas utilities' current prioritization flexibility be maintained, including using the PAC test as an input in that process.

3.5 Development, Updating and Use of Assumptions

Various assumptions are used at different stages of annual and multi-year DSM plans. Assumptions such as operating characteristics and associated units of resource savings for a list of DSM technologies and measures are referred to as "input assumptions". Assumptions relating to society's benefit of not having to provide an extra unit of supply of natural gas, or other resources (e.g., electricity, heating fuel oil, propane or water), and of avoided CO_2e emissions are referred to as "avoided costs".

3.5.1 Input Assumptions

Many participants endorsed the approach proposed earlier in this consultation which was utilized to determine the input assumptions for the 2010 and 2011 natural gas DSM plans. This approach consists of the Board overseeing the development of a common initial set of measure assumptions for prescriptive programs using an independent consultant and providing interested participants with an opportunity to comment on those inputs before they are finalized. The Revised Draft DSM Guidelines have retained this approach.

3.5.1.1 Updates to Input Assumptions During the DSM Plan

The input assumptions may change over time based on more accurate and up-to-date information resulting from the annual evaluation and audit process and other research as required. Staff proposes an updating process consistent with the current approach.

3.5.1.2 Use of Input Assumptions

As is the case under the current DSM framework, natural gas utilities should design, screen and evaluate programs using the best available information known to them at the relevant time.

There was consensus among participants to continue calculating the lost revenue adjustment mechanism ("LRAM") amounts based on the best available information. In the context of the current approach, the best available information refers to the updated input assumptions resulting from the evaluation and audit process of the same program year. For example, the LRAM amounts for the 2011 program year would be based on the updated input assumptions resulting from the evaluation and audit of the 2011 results.

In contrast, participants were highly divided with regard to using the best available information to determine the incentive amounts[14], which would be a departure from the current approach.[15] The natural gas utilities and three other participants argued in favour of maintaining the current approach to determine incentive amounts whereby input assumptions are locked-in at the beginning of the program year.[16] Union commented that CEA supported maintaining the current approach and agreed with CEA's statement that "there is ample opportunity to vet these assumptions in advance, with the benefit of providing greater certainty for program planning and implementation." Union further argued that "program changes that are necessitated by changing input assumptions without adequate lead time and notice to the marketplace will undermine the utility DSM programs and discourage future program participation." One environmental interest representative submitted that the

[14] The total incentive amounts include those described as shared savings mechanism amounts ("SSM"), whereby the incentive is based solely on the savings achieved, as well as incentives that are not solely based on savings and may be evaluated with a scorecard (e.g., market transformation and low-income programs).

[15] Under the current approach, incentive amounts are calculated using the input assumptions resulting from the previous program year. For example, under this approach the incentive amounts for the 2011 program year would be based on the updated input assumptions resulting from the evaluation and audit of the 2010 results.

[16] In practice, the process to update input assumptions may not be completed until some time during the program year. For instance, the Board rendered its Decisions on the input assumption updates for the 2010 program year on July 19, 2010 for Enbridge (EB-2010-0202) and June 22, 2010 for Union (EB-2010-0182).

natural gas utilities should not bear the risk of input assumption changes, especially those developed by an independent consultant.

Five ratepayer representatives as well as one environmental interest representative recommended that the incentive amounts should be based on the best available information, consistent with the approach used to determine LRAM amounts. One of these participants argued that it would encourage the natural gas utilities to “both continuously improve program design and consult with stakeholders, will reduce controversy and the potential for gaming and is not an undue risk for the LDCs at this stage.” Some of these participants noted that to do otherwise could result in ratepayers bearing the cost of incentive payments for savings that did not actually occur. One more participant noted that the “evaluation of programs using out of date information is neither logical nor good public policy.” One participant was of the view that the uncertainty introduced by determining incentives amounts based on the best available information is not nearly as uncertain as other risks faced by the natural gas utilities and that “the essence of managing any business, including a utility business, is managing uncertainty.”

Staff notes that four of the six participants in favour of using the best available information to determine the incentive amounts were under the impression that this was also CEA’s recommendation. To that regard, staff notes the following passage from the CEA report:

> There is considerable debate concerning whether input assumptions should be locked in during the program cycle or updated to reflect the best available information. From Concentric’s perspective, the Board should continue to update input assumptions to reflect the best available information based on the Evaluation Reports. This practice is consistent with the approach taken by the majority of other jurisdictions in our research survey. The advantage of this approach is that the Board will be better able to measure programs success against policy objectives when input assumptions are updated frequently. Another advantage is that the Board will be relying on the best available information for purposes of determining the lost revenue adjustment mechanism and the financial incentive for the utility.
>
> The primary disadvantage to frequent updates of input assumptions is cost. However, since the OEB has significant experience with DSM programs, Concentric would anticipate that the majority of changes to input assumptions would be refinements rather than major overhauls. Therefore, we would not expect the cost of frequent updates to be as significant in Ontario as it might be for a less mature DSM framework. Further, the information gathered from the annual Evaluation Reports should be very useful in making

> minor revisions to input assumptions based on empirical evidence, especially on issues such as free ridership.[17]

In response to a question posed by Enbridge, CEA clarified its recommendation indicating that it supports maintaining the approach under the current DSM framework:

> The reason for this distinction is that we understand LRAM to be a true-up mechanism for lost revenues due to the implemented DSM measures, and therefore a retrospective approach is appropriate. The SSM mechanism is designed to incent the utility for deploying DSM measures that meet targets set in advance with the full input of the utility, stakeholders, the Board, and its independent consultant. There is ample opportunity to vet these assumptions in advance, with the benefit of providing greater certainty for program planning and implementation. Further, with the adoption of BAT as a primary metric for setting targets, this should alleviate some of the concerns regarding measurement of TRC savings. Lastly, we would expect that the evaluation reports will be used to adjust input assumptions on a going forward basis, so any gaps should narrow over time. [18]

Staff notes that one of CEA's supporting arguments to maintain the approach under the current DSM framework was that "concerns regarding measurement of TRC savings" would be alleviated if its proposal to use market penetration of best available technology ("BAT") was adopted as the primary metric for setting targets. As noted later in section 3.8, staff does not support CEA's recommendation to adopt BAT as the primary metric. CEA's answer to Enbridge's question also clarified that there were circumstances where CEA may not support the current approach:

> We understand that input assumptions are primarily technology related, while adjustment factors are more attributable to program design and consumer behavior (and therefore more subject to change). To the extent that the Board sees a persistent gap between projected program results and those verified through the Evaluation Reports, it may wish to reconsider the trade-off between the planning certainty that our recommendation embraces, and the ability to verify benefits commensurate with the incentives awarded.[19]

---

[17] *Review of Demand Side Management (DSM) Framework for Natural Gas Distributors*, Concentric Energy Advisors Inc., March 19, 2010, pp. 61-62.
[18] *Response to Stakeholders' Written Questions*, Concentric Energy Advisors Inc., May 20, 2010, p. 19.
[19] Ibid.

To this point, staff notes that based on its review of Enbridge and Union's audited DSM results from 2007 to 2009, the audited total natural gas savings used to determine incentive amounts have in all years and for each natural gas utility been larger than the audited total natural gas savings used to determine the LRAM amounts. The difference has been 7% on average, ranging from 1% to 18%.

Staff recommends using updated input assumptions based on the best available information to determine both the LRAM and incentive amounts. Staff is of the view that using a consistent set of input assumptions for LRAM and incentive amounts will address some of the criticism about DSM activities that was raised earlier in this consultation. Also, while the current DSM framework does expect natural gas utilities to incorporate new information into program design and implementation as soon as available during the program year, basing the incentive amounts on input assumptions established at the beginning of the program year may provide a conflicting signal. For instance, while new information during the year might suggest that greater savings can be achieved by putting more effort into one program and less into another, the locked-in input assumptions would support the status quo. Using updated input assumptions instead should reward natural gas utilities to maintain a flexible approach and react to current information during the program year; an approach that would support the achievement of greater savings to everyone's benefit.

Staff also recommends that the preference to determine LRAM and incentive amounts should be to use measured actual results, instead of input assumptions, to the extent that it is feasible and economically practical. Staff notes that, consistent with this proposal, Enbridge and Union's approved amendments to their respective 2011 low-income weatherization plans (EB-2010-0175 and EB-2010-0055, respectively) indicate that the measurement of natural gas savings from these programs will be based on the results of the pre- and post-energy audits conducted by certified energy auditors on a custom basis.

3.5.2 Avoided Costs

As described earlier, assumptions relating to the societal benefit of not having to provide an extra unit of supply of natural gas, or other resources (e.g., electricity, heating fuel oil, propane or water), and of avoided CO_2e emissions are referred to as "avoided costs".

3.5.2.1 Updating of Avoided Costs

There was broad support among participants to maintain the current approach whereby the natural gas utilities submit avoided costs for approval as part of their multi-year DSM plan, with the commodity costs to be updated annually but all other avoided costs (e.g., avoided distribution system costs such as pipes, storage, etc.) to remain fixed for the duration of the plan. Staff concurs with this approach.

3.5.2.2 Costs of Carbon Dioxide Equivalent (“CO_2e”) Emissions

Staff notes that participants’ concerns on this issue did not rest on putting a value on CO_2e emissions per se, but rather on how to determine what that value should be. While staff proposes an approach to establish an initial value for CO_2e emissions for the purpose of the natural gas DSM framework, staff asks participants to provide further comments on whether they consider that any value should be included at this time.

Staff is cognizant of the fact that an Ontario market value for CO_2e emissions has not been established and that the Ontario government’s initiatives, in particular the Western Climate Initiative, may eventually provide such a value. However, the value of CO_2e emissions in the proposed Draft Revised DSM Guidelines would only apply for the purpose of screening programs to determine whether they should be considered at all for inclusion in the final DSM portfolio. Under these circumstances, and given the general support and the lack of opposition among participants to move away from the implicit price of $0 per tonne of CO_2e emissions in the screening test, staff recommends that a value of carbon be based on a simple and transparent approach.

As it would be the first time that a value for CO_2e emissions is introduced, and given the uncertainty surrounding when and at what level an eventual Ontario market value would be established, staff recommends using the lower end of the range recommended by CEA. This represents a value of $15 per tonne of CO_2e emissions. Staff recommends that this value be maintained at $15 per tonne of CO_2e emissions for the duration of the multi-year plan term. If market developments warrant re-examining this value during the term of the plan, the Board could entertain doing so as part of the annual process to update input assumptions.

Staff notes that the current British Columbia carbon tax rate of $20 per tonne of CO_2e emissions translates into a tax of $0.0380 per m^3 of natural gas.[20] This

[20] *Carbon Tax Return Natural Gas Retail Dealers Under the Carbon Tax Act For Reporting Periods between July 1, 2010 - June 30, 2011*, available at http://www.sbr.gov.bc.ca/documents_library/forms/0106-0710FILL.pdf

value is based only on the final combustion of natural gas, as opposed to the lifecycle emissions.[21] This implies that, at $15 per tonne of CO_2e, the equivalent per m^3 benefits of avoided CO_2e emissions would amount to $0.0285 per m^3; an increase of about 10% in natural gas avoided costs.[22]

3.5.2.3 Discount Rate

For the purpose of the TRC test, the total avoided costs resulting over the life of the DSM measures need to be discounted to a present value. CEA recommended using a social discount rate. CEA suggested that the social discount rate “could be based on the average yield on the Government of Canada long bond over a specified number of months.”

Two participants recommended continuing to base the social discount rate on each natural gas utility’s weighted average cost of capital, but suggested alternative approaches if the Board decides to adopt a social discount rate. One of these two participants argued that the alternative should be to use the Board’s Long Canada Bond Forecast as set out in its *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* dated December 11, 2009. The other of these two participants argued that the alternative should be to use a social discount rate of 8% net of inflation for both “DSM and supply-side investment projects” based on evidence this participant filed in the Board proceeding file number EB-2007-0707.

The natural gas utilities supported the use of a social discount rate based on “an established and accepted financial rate representing a societal investment perspective.” Three environmental and two ratepayer interest representatives also supported the use of a social discount rate, with one environmental interest representative noting that the social discount rate should be “as the government uses for considering long term options” and one ratepayer representative recommended that it be updated periodically. The natural gas utilities and one ratepayer representative also recommended that a single discount rate should apply to all electricity CDM and natural gas DSM programs.

Staff notes that there was broad support for a common social discount rate to be used by the natural gas utilities. Staff agrees that a common social discount rate should be used. However, staff asks participants for additional comments on a preferred approach to determine the social discount rate. Outlined in Table 1 below are suggested discount rates based on the comments received. Staff has also included two other options based on publicly available documents that staff considers relevant as they outline approaches that have been suggested to

[21] Confirmed by email from the British Columbia Ministry of Finance to Ontario Energy Board staff.
[22] Based on Union Gas Ltd.’s 2010 avoided cost, as shown in Appendix E to the *Audited Demand Side Management 2009 Annual Report* dated August 17, 2010.

determine the discount rate for the government of Ontario and the government of Canada (options 3. and 6., respectively). Staff notes that option 6 is based on an 8% real discount rate, a level consistent with the proposal advanced by one participant. Staff notes that this list of options is not meant to be exhaustive.

Table 1 – Social Discount Rate Options

Option	Nominal Rate
1. Board's Deemed Long-Term Debt Rate[a]	5.5%[b]
2. OPA's Discount Rate	6.1%[c]
3. Methodology Proposed by Peter Spiro for the Province of Ontario	7.1%[d]
4. ATWACC for Enbridge	7.6%[e]
5. ATWACC for Union	7.9%[f]
6. Treasury Board of Canada	10.2%[g]

[a] As per the methodology outlined in Appendix C to the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* dated December 11, 2009.
[b] Based on the Board's deemed long-term debt rate to be used for 2011 rate year cost of service applications for rates effective January 1, 2011. See Board letter dated November 15, 2010.
[c] The discount rate used by the OPA to evaluate electricity CDM programs is based on a real discount rate of 4% and an inflation rate of 2% (i.e., (1 + 4%)*(1 + 2%) – 1 = 6.08%). These values are consistent with the discount rate and inflation rate used to develop the OPA's Integrated Power System Plan that was submitted to the Board in August 2007. Reference: *OPA Conservation and Demand Management Cost Effectiveness Guide*, dated October 15, 2010.
[d] Using data "from the first half of 2008" as well as historical data going back to 1998, Peter Spiro recommends a real discount rate of 5% to be used by the province of Ontario. Assuming an inflation rate of 2%, Peter Spiro estimates the province of Ontario's nominal discount rate to be 7.1% (i.e., (1 + 5%)*(1 + 2%) -1 = 7.1%). Peter Spiro recommends reviewing the social discount rate annually. Reference: *The Social Discount Rate for Provincial Government Investment Projects*, pre-publication version of a chapter that was published in the book *Discount Rates for the Evaluation of Public Private Partnerships*, D. Burgess and G.P. Jenkins, eds., 2010, McGill-Queen's University Press, Montreal.
[e] Enbridge's after-tax weighted average cost of capital ("ATWACC") based on its approved 2007 capital structure and cost of capital, as outlined on p.2 of schedule 4 in its draft rate order filed April 2, 2008 of its 2008 to 2012 incentive rate case application (EB-2007-0615).
[f] Union's ATWACC based on its approved 2007 capital structure and cost of capital, as outlined in Exhibit A, Tab 2, Appendix A, Schedule 4, p.1 of its 2009 Earnings Sharing & Disposition application dated April 22, 2010 (EB-2010-0039).
[g] *Canadian Cost-Benefit Analysis Guide*, Her Majesty the Queen in Right of Canada, represented by the President of the Treasury Board, 2007. The *Canadian Cost-Benefit Analysis Guide* recommends "that a real rate of 8 per cent be used as the discount rate for the evaluation of regulatory interventions in Canada." Assuming a 2% inflation rate, the nominal discount rate recommended is 10.2% (i.e., (1 + 8%)*(1 + 2%) -1 = 10.2%).

Staff notes that CEA recommended "reducing the discount rate to place more value on savings that are expected to occur in future years." Enbridge currently uses a discount rate of 9.14% and Union a discount rate of 10%. Staff believes that the use of a lower discount rate would be consistent with putting a greater emphasis on deep measures, an approach that was broadly supported by participants.

Staff recommends that the chosen discount rate be fixed for the duration of the proposed three-year term of the plan. At the end of the three-year term, the Board may wish to consider updating the discount rate.

3.6 Adjustment Factors for Screening and Result Evaluation

The assumptions described in section 3.5 enable the calculation of savings accruing from specific measures or programs. Adjustment to those results must be considered to take into account the extent to which the natural gas utility contributed to their achievement and the extent to which the savings are expected to persist. This exercise is done through the use of adjustment factors.

The four adjustment factors that are the topic of this section are free ridership, spillover, attribution and persistence.

3.6.1 Free Ridership and Spillover

A free rider is a "program participant who would have installed a measure on his or her own initiative even without the program."[23] In contrast, spillover refers to customers that adopt energy efficiency measures because they are influenced by a natural gas utility's program-related information and marketing efforts, but do not actually participate in the program.

CEA recommended for simplicity to either assume that free ridership is offset by spillover or to multiply reported energy savings by a designated factor to adjust for those effects. Some participants agreed with CEA's view that free ridership should be assumed to be offset by the spillover effects since, they argued, it would encourage increased collaboration and coordination between electricity and natural gas utilities and it would streamline DSM program planning and evaluation process. However, many participants opposed assuming they offset each other because, in their view, doing so would provide an incentive to the natural gas utilities to implement programs with the most free riders; there is no evidence before the Board that they actually do offset each other or that the net impact is a fixed percentage; and both of these adjustment factors depend on the

[23] Violette, Daniel M. (1995) *Evaluation, Verification, and Performance Measurement of Energy Efficiency Programs*. Report prepared for the International Energy Agency.

program design and the targeted customer segments. Two representatives of ratepayer interests argued that the natural gas utilities should not receive an incentive for spillover effects.

Staff agrees with the view that free ridership and spillover effects should not be assumed to offset each other because their net impact depends on the design of the program and the targeted customer segments. In staff's view, assuming they offset each other, or more generally that the net impact is a fixed percentage, would not provide adequate incentive for the natural gas utilities to design and implement programs that minimize free ridership.

Staff is of the view that all adjustment factors considered, including free ridership and spillover, should be assessed for reasonableness prior to the implementation of the multi-year plan and annually thereafter, as part of each natural gas utility's ongoing program evaluation and audit process. While the Revised Draft DSM Guidelines require each natural gas utility to always provide information on free ridership for all its applicable programs, a natural gas utility has the option to request the inclusion of spillover effects for any of its programs. Requests for the Board to consider spillover effects will need to be supported by comprehensive and convincing empirical evidence which clearly quantify the effects that the spillover of a specific program has had on program savings and the natural gas utility's revenue.

3.6.2 Attribution

Attribution relates to whether the effects observed after the implementation of a natural gas utility's DSM activity can be attributed to that activity or at least partly result from the activities of others.

CEA recommended that attribution be based on the percentage of total dollars spent by the natural gas utilities on designing, developing and delivering the joint DSM programs. CEA also recommended that the natural gas utilities should provide evidence for the Board's consideration if they wished to claim any percentage greater than that based on what they actually spent.

Most participants representing ratepayer interests supported CEA's recommendation, with one ratepayer representative recommending that attribution should be done on a case-by-case basis instead. The natural gas utilities opposed this approach, arguing that "percentage of total dollars spent" is not necessarily reflective of each partner's contribution and the requirement to file evidence to support an alternative share would discourage natural gas utilities from undertaking such partnerships.

Staff notes that many participants stressed the need for greater coordination of electricity CDM and natural gas DSM activities. Accordingly, staff finds it appropriate to separate the issue into two categories: attribution between rate-regulated natural gas utilities and rate-regulated electricity distributors, and attribution between rate-regulated natural gas utilities and other parties (e.g., non-rate-regulated entities such as agencies and various levels of government, non-rate-regulated private companies, etc.).

Staff proposes that all the natural gas savings be attributed to rate-regulated natural gas utilities for electricity CDM and natural gas DSM programs jointly delivered with rate-regulated electricity distributors and vice versa for electricity savings. Staff notes that there are relatively little natural gas savings associated with electricity CDM programs and, likewise, there are relatively little electricity savings associated with natural gas DSM programs. In staff's view, therefore, each type of utility has little incentive to finance the other type of utility's programs and each is likely to pay for the entirety of the programs associated with its respective energy source. Staff concludes that a finer scale of attribution between the rate-regulated natural gas utilities and electricity distributors is therefore not warranted. Staff sees the continuation of the simplified approach whereby all energy savings are attributed based on the type of commodity delivered by each rate-regulated utility as conducive to partnerships between the two sectors. Staff notes that such partnerships should result in economies of scale and economies of scope to the benefit of all ratepayers.

As proposed by the natural gas utilities, staff recommends that attribution of savings between rate-regulated natural gas utilities and other parties (e.g., governments, non-rate-regulated private sector, etc.) be based primarily on the shares established in the partners' agreement. Staff also recommends that where a natural gas utility's allocated share in the agreement is more than 20% of the share that would have been allocated based on a "percentage of total dollars spent" basis, an explanation for the difference should be provided. Staff further recommends that the natural gas utilities would file expected spending for each of the partners before the program is launched and the actual amount spent by each partner within each program year. As partnerships do not always evolve as originally planned, this additional information will help the Board and stakeholders to assess the reasonableness of the shares allocated in the agreement reached prior to the program's launch and the actual contribution the natural gas utility made to the program.

In the absence of an agreement of the partners on the sharing of savings resulting from the program, the attribution will be based on CEA's proposal (i.e. based on the percentage of total dollars spent by the natural gas utility).

As described in section 3.8, staff recommends moving away from measuring success and providing an incentive based on a TRC-based metric and proposes to use other metrics, one of which is natural gas savings. Hence, for the purpose of determining the incentive and the LRAM amounts, the percentage of attribution will only be used to determine how much of the natural gas savings resulting from the jointly-delivered programs will accrue to the natural gas utilities; it will not be used for other resource savings.

Staff notes that section 7.1 of the Conservation and Demand Management Code for Electricity Distributors (“CDM Code”) issued September 16, 2010 outlines the attribution rules under the electricity CDM framework. Staff’s understanding is that attribution between rate-regulated natural gas utilities and electricity distributors under the CDM Code is intended to be as proposed by staff in this paper for the Revised Draft DSM Guidelines: all energy savings are to be attributed based on the type of commodity delivered by each rate-regulated utility.

With regard to attribution between rate-regulated electricity distributors and partners other than the rate-regulated natural gas utilities, the CDM Code stipulates that the rate-regulated electricity distributor may claim 100% of the benefits of a CDM program if its role is determined to be central. Centrality is established under the CDM Code if a rate-regulated electricity distributor contributed more than 50% of the program funding or if it initiated the partnership, initiated the program or initiated the implementation of the program. This “centrality approach” is identical to the approach under the current natural gas DSM framework. Staff notes that no participant in this consultation, nor CEA, supported the continuation of the “centrality principle”.

While staff’s proposal for attribution between rate-regulated natural gas utilities and partners other than the rate-regulated electricity distributors differs from the corresponding approach under the CDM Code, it is also consistent in many regards. Under staff’s proposal for the Revised Draft DSM Guidelines, the natural gas utilities may still claim up to 100% of the savings. The main difference is that in order to claim 100% of the savings, the natural gas utilities must provide evidence that this share is reflective of their role for that program, whereas under the CDM Code a rate-regulated electricity distributor only needs to show that its role amounted to at least 50% of the effort to be entitled to 100% of the benefits. In staff’s view, there is a trade-off between having a more granular approach in terms of regulatory burden and a more expedient approach whereby there may be a greater risk that the level of effort is not commensurate with the incentive provided and could be unfair to the ratepayers. Staff believes that the recommended approach for the Revised Draft DSM Guidelines is responsive to the comments received in this consultation.

3.6.3 Persistence

Persistence of DSM savings can take into account how long a DSM measure is kept in place relative to its useful life, the net impact of the DSM measure relative to the base case scenario, and the impact of technical degradation. For example, if an energy efficient measure with a useful life of 15 years is removed after only two years, most of the savings expected to result from that installation will not materialize. As for technical degradation, it refers to the potential for the DSM measure's performance to decrease as it gets closer to the end of its useful life (e.g., the achieved efficiency level of a natural gas furnace may decrease as it ages).

Participants were generally of the view that persistence should not be assumed to be 100% of the measures' useful life, with the natural gas utilities suggesting that it is "an evaluation issue and is addressed on a program by program basis as needed."

Staff is of the view that there is a need for a more thorough consideration of savings persistence which may be driven, among other things, by how long a DSM measure is kept in place by the customer and technical degradation. Staff also notes that another aspect that can be considered as part of the persistence factor is what Joseph Eto refers to as "dynamic free riders."[24] As he explains "free riders have typically been limited to those free riders who would have adopted reasonably contemporaneously with a program offering (i.e., for a particular program year)." In contrast, dynamic free riders are those who would have implemented the DSM measure on their own in the future (e.g., in two years time), but their implementation date was accelerated by the program offering. Staff notes that in this case, the savings resulting from the DSM program would only accrue for up to the period by which the adoption was accelerated (e.g., two years), instead of the entire useful life of the measure.

More generally, staff notes that an important consideration when assessing the persistence of savings is the fact that some energy efficient equipments have a much longer life than the base case equipment. For example, if an efficient natural gas furnace (model A) with a 25-year useful life is used to replace a homeowner's furnace (model B) with a remaining useful life of 5 years, an assumption must be made with regard to what would have happened under the base case. Would the average homeowner have opted to replace its furnace for a more efficient furnace (model C) on its own in five years from now? If so, staff notes that the estimated savings for the first five years should be based on the savings of model A compared to model B, but the savings over the next 20 years should be calculated by comparing model A to model C.

[24] Eto, J, (1998) *Guidelines for assessing the Value and Cost-effectiveness of Regional Market Transformation Initiatives*. Northeast Energy Efficiency Partnership, Inc., p. 26.

In staff's view, another important consideration in assessing the persistence of savings is potential changes in usage pattern. For example, large custom commercial and industrial DSM projects with expected useful life of 20 years or more may not fully materialize if the business benefiting from the custom measure operates at lower levels or closes down its processes within that time period. Given the natural gas utilities' 15 years of experience delivering natural gas DSM programs in Ontario, staff proposes that the natural gas utilities assess the historical persistence of savings of custom DSM projects and commercial and industrial DSM programs in general and provide the resulting information to and consult with their stakeholders to determine whether any persistence adjustments to the savings of those programs would be warranted going forward.

Staff recognizes that there may be a trade-off between greater accuracy and the cost associated with developing persistence factors. For instance, it may be appropriate to carefully develop persistence factors for programs with significant budgets and savings, while other lower budget programs with measures that would not reasonably be uninstalled prior to the end of their useful life could be assumed to have a persistence factor of 100%. In either case, staff would expect the natural gas utilities to provide a rationale for the persistence factor it is using for each of its programs. Staff expects the natural gas utilities' stakeholder engagement process will provide an opportunity for stakeholders to guide the natural gas utilities in determining the extent to which persistence factors should be developed for each program.

3.7 Budgets

This section provides a discussion on the overall natural gas DSM budget for each natural gas utility as well as a discussion on the DSM budget components by generic program type.

3.7.1 Overall Natural Gas DSM Budget

The approved 2011 DSM budgets for Enbridge and Union are $28.1 million and $27.4 million, respectively.[25] This represents about 2.8% of Enbridge's approved 2011 distribution revenues and about 4.1% of Union's forecast 2011 distribution revenues.[26] NRG does not currently undertake rate-funded natural gas DSM activities. A discussion on the overall natural gas DSM budget under the term of the plan is provided in the sections below.

3.7.1.1 Background and Participants' Comments

CEA recommended minimum annual DSM budgets for Enbridge and Union of 3% of their respective annual distribution revenues. CEA also advised that a Board-recommended range of between 4.0% and 6.0% of distribution revenues should be established. CEA noted that its recommendations are based on its understanding of Ontario's regulatory and public policy environment, and informed by its review of Canadian jurisdictions and "jurisdictions in the U.S. [that] were chosen because they were determined to be states which had the highest per capita spending on natural gas DSM programs." Enbridge and Union commented that their respective DSM budget could escalate to that range, if the recommendation is adopted by the Board.

One ratepayer representative was of the view that the entire DSM budgets should be government-funded, as opposed to being funded through distribution rates. A few participants noted that the PEG report failed to provide conclusive

[25] See the Board's Decision and Order dated September 24, 2010 in Enbridge's 2011 DSM plan application – EB-2010-0175, and Decision and Order dated September 9, 2010 in Union's 2011 DSM plan application – EB-2010-0055. See also the Board's Decisions and Orders dated December 20, 2010 on Enbridge and Union's application to amend their respective low-income weatherization plan within their approved 2011 DSM plans (Board file number EB-2010-0175 and EB-2010-0055, respectively).

[26] See the Board's Decision and Order dated November 25, 2010 in Enbridge's application for new rates for 2011 (Board file No. EB-2010-0146). In its Decision and Order, the Board approved the Settlement Agreement dated November 23, 2010, which set Enbridge's 2011 distribution revenues at $988.6 million. See also the Board's Decision and Order dated November 16, 2010 in Union's application for new rates for 2011. Union indicates in its draft rate order dated November 18, 2010 that, further to the Board's Decision and Order, it forecasts collecting distribution revenues of $674.9 million in 2011.

evidence of the impact of DSM programs, a finding that would not support a rapid expansion of DSM budgets. A number of participants representing ratepayer interests were of the view that the Board should holistically consider "green energy policies" undertaken in Ontario before determining whether it should recommend increasing the natural gas utilities' annual DSM budgets. Some of these participants noted their concerns with what they viewed as a U.S. sample skewed towards utilities with the highest DSM spending as forming part of the basis for CEA's recommendation. One of those participants also noted that CEA's U.S. weighted average DSM spending is heavily influenced by one observation in particular. This participant estimated that removing this observation reduces the sample weighted average annual DSM budget as a percent of distribution revenues from 3.9% to 3.04%, which is not inconsistent with the Ontario natural gas utilities current spending level.

Participants representing environmental interests found that CEA's proposed budget increase was insufficient. One of them argued that "the economic, environmental, and other policy imperatives for significantly increasing the level of investment in natural gas DSM in Ontario have never been more compelling." This participant also argued that DSM budget increases are warranted to "allow all customers to be meaningful program participants over a reasonable timeframe." The same participant noted that CEA used 2007 and 2008 data for the U.S. sample that form part of the basis for its recommendation. This participant argued that, based on its investigation of five of the ten utilities in the CEA sample, the simple average spending for these five utilities would increase from their 3.9% of distribution revenues based on the data in the CEA report to about 12% in "2011/2012". Two participants representing environmental interests commented that the DSM budgets should increase, perhaps over a few years, to a level sufficient to allow the natural gas utilities to capture all of the practical and cost-effective natural gas DSM savings in their respective franchise areas.

Two ratepayer representatives supported CEA's recommendation to establish a minimum DSM budget of 3% of distribution revenues, with one of them suggesting that it should be increased by one percent per year[27], while two other participants objected to the notion of a spending floor. One participant proposed the establishment of a maximum budget, while the natural gas utilities and representatives of environmental interests objected to a spending cap. Many participants commented that tying DSM budgets to distribution revenues would be arbitrary.

In his letter to the Board dated July 5, 2010, the Minister indicated his support for the expansion of "DSM efforts in general". Similar comments were reflected in

[27] More specifically, this participant recommended that the DSM budget be increased from 3% of distribution revenues in the first year, to 4% of distribution revenues in the second year, 5% in the third year and 6% in the fourth year.

Volume 2 of the Environmental Commissioner of Ontario's ("ECO") 2009 Annual Progress Report:

> We urge that conservation spending by gas utilities be expanded, given the very high net benefits per dollar spent and the low level of current spending on conservation by gas utilities in Ontario compared to other jurisdictions.[28]

Most participants agreed that budget escalation should be subject to the constraint that undue rate increases do not occur. However, one participant representing environmental interests commented that "the Board should be more concerned with customer bills than rates" while another environmental interest representative argued that the burden of proof that undue rate impact would occur should lie with "any party who opposes spending what is necessary to achieve maximum cost-effective efficiency."

Four representatives of ratepayer interests commented that when assessing rate impacts, the Board should take into account not only the DSM budget amount but also all other DSM rate funding required such as the incentive amounts. One ratepayer representative also commented that the costs of all electricity CDM and natural gas DSM activities that impact customers should be taken into account, while another ratepayer representative provided a list of costs associated with the government's "green energy policies" that, in their view, should also be considered by the Board.

3.7.1.2 Staff Discussion

Staff is of the view that estimating annual natural gas DSM budgets as a percent of distribution revenues provides a useful, albeit imperfect, measure of relative magnitude of natural gas DSM budgets across natural gas utilities. Combined with other information, such as specific circumstances in each jurisdiction and distributor service area, this measure can help guide the starting and end point of the budget path and the resulting escalation factor. However, staff does not support using this measure as a mechanistic way of adjusting the DSM budget based on the approved distribution revenues of each year of the plan as this would introduce unwarranted uncertainty with no evident benefit.

In staff's view, the CEA's recommended range is based on a jurisdictional review of "leading jurisdictions". As noted earlier, while one ratepayer representative expressed concerns with the disproportionate influence of one observation in CEA's U.S. sample, one representative of environmental interests pointed to the vintage of the CEA's data (i.e., 2007 and 2008) as having an opposite influence on the results. Under the circumstances, staff finds CEA's range to be a

[28] *Re-thinking Energy Conservation in Ontario – Results, Annual Energy Conservation Progress Report – 2009 (Volume Two)*, released on November 30, 2010, p. 2.

reasonable reflection of the level of DSM budgets found in those leading jurisdictions.

3.7.1.3 Staff Options

Staff also notes that throughout this consultation participants expressed diametrically opposed views with regard to the annual DSM budget path. Staff finds it useful to outline what appears to be the five primary guiding principles that may inform the level and rate of increase of natural gas DSM budgets:

A) Supporting an increase emphasis on deep measures;

B) Ensuring equitable access to DSM programs among and across all rate classes to the extent reasonable, including low-income customers;

C) Increasing coordination and integration of certain natural gas DSM programs with electricity CDM programs;

D) Ensuring no undue rate impacts; and

E) Ensuring no undue level of cross-subsidization within and across rate classes.

With regard to principle A), staff notes that there may be an opportunity for the natural gas utilities to capture some of the momentum that was created by the suite of federal ecoENERGY Retrofit programs, which stopped taking new applications as of April 1, 2010, and the Ontario Home Energy Savings Program, ("HESP") which is expected to stop taking new applications as of April 1, 2011.[29] According to the Ontario Ministry of Energy "the federal ecoENERGY Retrofit program, along with the provincial Ontario Home Energy Savings Program, helped over 393,000 homeowners with energy audits and helped nearly 250,000 homeowners with energy savings and retrofits."[30] Based on Statistics Canada 2006 Census data, staff estimates that the approximate 250,000 retrofits would amount to less than 10% of the Ontario housing stock, which indicates that there remains a significant potential for home retrofit measures that could be supported to some degree via the natural gas utilities' DSM programs. Staff notes the ECO's comment that "About 63 per cent of the energy savings resulting from HESP are related to heating homes with natural gas; HESP thus complements

[29] The Ontario Government announced on p. 38 of its *Ontario's Long-Term Energy Plan*, released on November 23, 2010, that the "Despite the federal government's early withdrawal from funding this conservation program in March 2010, Ontario will continue to support the Home Energy Savings Program until March 31, 2011."
[30] *Ontario's Long-Term Energy Plan*, released on November 23, 2010, p. 38.

natural gas utilities' demand-side management activities since gas distributors offer limited assistance."[31] The ECO further commented that:

> Ontario is forecasting large budget deficits for coming years, and it is therefore possible that the program will not be renewed because of pressure to reduce spending. Facing these financial pressures, the government has perhaps three options: let the program end (encouraging its adoption by a third party like gas utilities); renew the program with its current design (using tax or ratepayer money); launch a redesigned successor program (e.g., providing only audits, or lowering grant amounts, or targeting older high consumption homes).[32]

Staff notes that while principles A), B) and C) would tend to support larger natural gas DSM budgets, principles D) and E) would tend to dampen the pace of DSM budget growth and principle E) might even indicate that the DSM budget should be reduced. On that latter point, staff notes that in its E.B.O. 169-III Report of the Board dated July 23, 1993 the Board noted on page 85 that:

> 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 ... 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.

Staff notes that the first Board-approved DSM budgets for Enbridge[33] and Union[34] under the E.B.O. 169-III Report of the Board were for their 1995 rate year. Enbridge and Union's 1995 Board-approved DSM budgets were $6.3 and $4.2 million, respectively. As noted earlier, Enbridge and Union's Board-approved 2011 DSM budgets are $28.1 and $27.4 million, respectively. This implies an average compounded annual increase of about 10% for Enbridge and 12% for Union. While staff recognizes those increasing DSM budgets have meant that a greater number of participants can be reached every year, the cross-subsidization provided by non-participants has also increased beyond those experienced at the time the E.B.O. 169-III Report of the Board was issued.

[31] *Re-thinking Energy Conservation in Ontario – Results, Annual Energy Conservation Progress Report – 2009 (Volume Two)*, released on November 30, 2010, p. 46.
[32] Ibid.
[33] Enbridge Gas Distribution Inc. was then known as The Consumers' Gas Company Ltd.
[34] Union Gas Ltd. and Centra Gas Ontario Inc. were amalgamated under Union Gas Ltd. effective January 1, 1998.

Staff notes that the Board further indicated on page 87 of its E.B.O. 169-III Report of the Board that:

> 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.

Staff notes that, everything else being the same, increasing the focus on deep measures would imply that fewer participants can be reached and that the cost per participant would be larger on average; a result that would increase intra-class subsidization. This can be illustrated by Union's estimate that the average 2009 total cost per low-income participant for its Helping Homes Conserve program[35] averaged $121 whereas its average 2009 total cost per low-income participant for its deep measures[36] was $2,750.[37] Staff notes that staff's proposal to screen low-income programs at the lower 0.7 threshold could further increase those average total cost per low-income participant. For instance, Union's approved amendment to its 2011 low-income DSM funding indicates that it will require about $4,125 per participant for its low-income weatherization program under a TRC threshold of 0.7.[38] While average natural gas DSM program funding per non-low-income participant would be lower than for low-income customers[39], this illustrates the magnitude of the difference in funding requirements per participant between "shallow" and "deep" measures.

Increasing the focus on deep measures while maintaining or increasing access to DSM programs among and across all rate classes would require budget increases. Depending on the level of emphasis on deep measures considered, the budget increases required may lead to concerns about rate impacts, as expressed under principle D.

---

[35] Measures offered by this program are energy efficient showerheads, bathroom and kitchen aerators, 2m pipe wrap, and programmable thermostats.

[36] Deep measures offered were attic, wall and basement insulation, and draft proofing.

[37] Union's responses dated November 13, 2009 to interrogatories on its 2010 low-income DSM plan in proceeding EB-2009-0166, Exhibit C3.1.

[38] Union's application dated November 20, 2010 requesting an amendment to its 2011 DSM plan to increase its low-income DSM plan (EB-2010-0055) indicates that $1.65 million will be required to achieve a target of 400 houses weatherized, which implies an average of $4,125 per house. The $1.65 million is for "Measures/Audits and Program Administration." Other related budget items not included in staff's estimated $4,125 average are "Marketing and Education", "Data Analysis", "Basic Audit", and "Research & Evaluation" which brings the total incremental DSM budget requested to $2.465 million. Staff only considered the $1.65 million for "Measures/Audits and Program Administration" to calculate the estimated $4,125 average as staff understands this to be consistent with how Union calculated its previously mentioned 2009 average of $2,750.

[39] Under staff's proposal, low-income DSM programs will be provided at no cost to low-income customers whereas non-low-income customers will have to defray a portion of the costs of the DSM measures available to them.

Staff also notes that, if the natural gas utilities do not increase their focus on deep DSM measures in general, it may become increasingly difficult for them to cost effectively spend their DSM budgets at the current levels as there is some evidence that the potential to roll out "shallow" measures has already been partly tapped. For instance, Enbridge noted in its 2011 DSM plan application that:

> … many traditional gas utility DSM programs have reached, or are close to reaching maturity (e.g. high efficiency furnaces, programmable thermostats, low-flow showerheads), and the pressure to maximize TRC with a limited budget does not leave room for many new or emerging measures which are typically low in TRC value.[40]

Staff notes the ECO's comment that "in addition to the government, the primary delivery agents for natural gas conservation in Ontario have been the two large gas utilities, Enbridge Gas Distribution and Union Gas."[41] Accordingly, it may be that any identified need to increase natural gas DSM activities and funding in Ontario via the natural gas utilities or other entities could be through other parties, such as the Ontario government. However, staff is not aware that the Ontario government or other parties intend to significantly increase their contribution towards increased natural gas DSM activities at this time.

In light of the above discussion on cross-subsidization, potential rate impacts, and the lack of indication that alternative sources of DSM budget funding may be forthcoming, staff notes that if the current DSM budget levels are at or near "undue levels" of cross-subsidization it may be that a 0% increase in the DSM budget, or even a decrease in DSM budget is warranted. Staff suggests that an assessment of what may constitute "undue levels" of cross-subsidization and undue rate impacts in the natural gas DSM context may be warranted to ensure that current and future natural gas DSM budgets are in line with these principles.

Based on the above discussion, staff wishes to outline a budget option for participants comments.

[40] Board proceeding EB-2010-0175, Enbridge's 2011 DSM plan application dated May 28, 2010, Exhibit B, Tab 1, Schedule 2, p. 2.
[41] *Re-thinking Energy Conservation in Ontario – Results, Annual Energy Conservation Progress Report – 2009 (Volume Two)*, released on November 30, 2010, p. 37.

Budget Option 1: Maintain DSM Budgets at their 2011 Board-approved Levels throughout the Three-year Term

Considerations:

- Enbridge's DSM budget would stay at $28 million and Union's DSM budget would stay at $27 million;
- Enbridge's DSM budget level would fall slightly below the minimum 3% of distribution revenues recommended by CEA at 2.7% in 2014, while Union DSM budget would be about 3.8% of its distribution revenues in 2014;[42]
- There would be no additional rate impact;
- Any change in the level of cross-subsidization would be the result of changes from program offerings (e.g., if there is an increase focus on deep measures), and not from the DSM budget levels;
- Under constant budget levels, an increased focus on deep DSM measures would result in fewer participants being reached;
- If there is no shift to deeper DSM measures, it may become harder for the natural gas utilities to spend their budgets on more "shallow" measures, a consideration that would support not increasing or even decreasing the DSM budget levels;
- An increased focus on low-income DSM programs to support coordination with electricity CDM programs could mean increasing the budget allocated to the low-income customers while reducing by an equivalent amount the commercial, industrial and/or the remainder of the residential sector budget;
- Other parties, such as the Ontario government, could supplement those DSM budget levels through alternative sources of funding.

Staff supports in principle the rational coordination and integration of natural gas DSM programs with electricity CDM programs, as reflected in objective C). Staff notes that, given the scale of the planned electricity CDM budgets to December 31, 2014, coordination and integration of certain natural gas DSM programs with the electricity CDM programs could require large natural gas DSM budget increases. Staff estimates, for example, that if the low-income natural gas DSM and electricity CDM programs were integrated, whereby each low-income customer who owns a natural-gas-heated house and participates in an electricity CDM program would be offered all natural gas DSM measures that pass the screening test, Enbridge and Union's low-income DSM budgets may

[42] The approved 2011 DSM budgets for Enbridge and Union are $28.1 million and $27.4 million, respectively. This represents about 2.8% of Enbridge's approved 2011 distribution revenues and about 4.1% of Union's forecast 2011 distribution revenues. Assuming each gas utility's distribution revenues increases at the Bank of Canada's target inflation rate of 2% per year from their 2011 distribution revenue levels, Enbridge and Union's 2014 gas DSM budgets under option 1 would respectively represent 2.7% and 3.8% of their distribution revenues.,.

have to increase to about $15 and $8 million in 2012, respectively, and increase at 20% per year thereafter.

Staff anticipates that the budget increase required to support the full integration of all electricity CDM and natural gas DSM programs over the proposed plan term would result in the natural gas DSM budgets representing a share of distribution revenues above and beyond the CEA recommended range. Staff notes that an intermediate approach could be the integration of low-income programs only. Staff notes that the OPA has already consulted and undertaken work to support the coordination and integration of low-income electricity CDM programs with natural gas DSM programs.[43]

As noted in section 3.3.1, staff recommends that one of the guiding principles for the DSM portfolio should be the pursuit of deep energy savings. As illustrated earlier, staff notes that to support an increased focus on deep measures, while maintaining to the extent reasonable an equitable access to DSM programs among and across all rate classes, would require increasing the natural gas DSM budget levels.

Outlined below is a second staff option that could support greater coordination of natural gas DSM programs with electricity CDM programs as well as support for a greater focus on deep DSM measures.

[43] In his July 5, 2010 letter, the Minister indicated his support for “Co-ordinated efforts between gas distributors and the OPA's efforts pursuant to the aforementioned direction to the OPA.”

Budget Option 2: Set DSM Budgets to Support Increased Focus on Deep Measures & Low-Income Program Integration with Electricity CDM

Considerations:

- Enbridge's DSM budget would increase from $28 million in 2011 to $76 million in 2014 and Union's DSM budget would increase from $27 million in 2011 to $62 million in 2014;
- Enbridge's DSM budget would represent about 7.3% of its distribution revenue in 2014 while Union's DSM budget would be about 8.7% of its distribution revenues in 2014;[44]
- Using the methodology outlined in the CEA report[45], staff estimates that the average annual natural gas DSM funding per customer would increase from $15 in 2011 to $40 in 2014 for Enbridge's customers and from $21 in 2011 to $47 in 2014 for Union's customers;
- The level of cross-subsidization provided by customers not participating in natural gas DSM programs would increase as a result of the greater focus on deep DSM measures and from the larger DSM budget levels;
- The increasing DSM budgets could both support a greater focus on deep DSM measures while reaching as many or more participants;
- If there is no shift to deeper DSM measures, it will be difficult for the natural gas utilities to spend those increasing budgets on more "shallow" measures;
- Would support the full integration of low-income natural gas DSM programs with electricity CDM programs without reducing other budget components. Would also support greater coordination of other natural gas DSM and electricity CDM programs;
- Other parties, such as the Ontario government, could provide alternative sources of funding which could reduce the distribution rate-funded portion of the proposed DSM budgets under this option.

Another alternative budget option would be to escalate both Enbridge and Union's DSM budget to about 6% of their distribution revenues by 2014, which is the end of the range recommended by CEA. Under this option Enbridge's 2011 DSM budget would be escalated by 30% per year, whereas Union's 2011 DSM budget would be escalated at 15% per year. Staff notes that the natural gas utilities did not express concerns about escalating their respective DSM budget

[44] The approved 2011 DSM budgets for Enbridge and Union are $28.1 million and $27.4 million, respectively. This represents about 2.8% of Enbridge's approved 2011 distribution revenues and about 4.1% of Union's forecast 2011 distribution revenues. As Enbridge and Union's distribution revenues may increase of the proposed term of the gas DSM framework, those percentages may decrease somewhat over time under option 1.
[45] In its report, CEA provided a high level estimate of the potential impact of increasing DSM funding on Enbridge and Union' customers by dividing annual DSM budgets by the total number of customers in each gas utility's service area.

to the CEA recommended range, and staff views the proposals outlined in the CWG Report as indicative that they could rationally accommodate this DSM budget increase option.[46]

Staff notes that while this approach would result in the natural gas utilities' DSM budgets representing about 6% of their respective distribution revenues in 2014, it would also result in DSM budgets that diverge in absolute magnitude. On that point, staff notes that the Partial Settlement in the 2006 generic DSM proceeding (EB-2006-0021) indicated "the desire by some parties that the difference between the level of spending by EGD and Union be narrowed." Staff invites participants to comment on the continued desirability of having similar budget amounts for Enbridge and Union, particularly as the difference in their customer base has widened, as opposed to similar percent of distribution revenues allocated to DSM activities.

[46] The CWG Report indicates that Enbridge proposed a DSM budget of $9.7 million for 2010. This compared to Enbridge's 2009 Board-approved budget for low-income DSM of $1.6 million. Union proposed a DSM budget of $3 million for 2010. This compared to Union's 2009 Board-approved budget for low-income DSM of $1.7 million.

Budget Option 3: Increase the Natural Gas Utilities' DSM budgets to about 6% of their Respective Distribution Revenues by 2014

Considerations:

- Enbridge's DSM budget would increase from $28 million in 2011 to $62 million in 2014 and Union's DSM budget would increase from $27 million in 2011 to $42 million in 2014;
- Enbridge's DSM budget would represent about 5.9% of its distribution revenue in 2014 while Union's DSM budget would be about 5.8% of its distribution revenues in 2014;[47]
- Using the methodology outlined in the CEA report[48], staff estimates that the average annual natural gas DSM funding per customer would increase from $15 in 2011 to $33 in 2014 for Enbridge's customers and from $21 in 2011 to $31 in 2014 for Union's customers;
- The level of cross-subsidization provided by customers not participating in natural gas DSM programs would increase as a result of the greater focus on deep DSM measures and from the larger DSM budget levels;
- The increasing DSM budgets could provide some support for a greater focus on deep DSM measures while reaching as many or more participants;
- If there is no shift to deeper DSM measures, it may be difficult for the natural gas utilities to spend those increasing budgets on "shallow" measures;
- An increased focus on low-income DSM programs to support integration with electricity CDM programs could result to some degree of budget reallocation to low-income DSM programs and away from other budget components. The increasing overall natural gas DSM budgets could provide some support for greater coordination of other natural gas DSM and electricity CDM programs;
- Other parties, such as the Ontario government, could supplement those DSM budget levels through alternative sources of funding.

Table 2 below outlines the proposed budget paths for Enbridge and Union under the three Budget Options. Those options set out a range from $28 to $76 million for Enbridge's 2014 DSM budget and from $27 to $62 million for Union's.

[47] The approved 2011 DSM budgets for Enbridge and Union are $28.1 million and $27.4 million, respectively. This represents about 2.8% of Enbridge's approved 2011 distribution revenues and about 4.1% of Union's forecast 2011 distribution revenues. As Enbridge and Union's distribution revenues may increase of the proposed term of the gas DSM framework, those percentages may decrease somewhat over time under option 1.

[48] In its report, CEA provided a high level estimate of the potential impact of increasing DSM funding on Enbridge and Union' customers by dividing annual DSM budgets by the total number of customers in each gas utility's service area.

Table 2 – Proposed Target DSM Budgets ($ million)

		Approved 2011 DSM Budget	Recommendation for 2012 to 2014		
		2011	2012	2013	2014
Option 1: 0% budget growth	**Enbridge**	28	28	28	28
	Union	27	27	27	27
Option 2: Deep + LI Integration	**Enbridge**[a]	28	47	60	76
	Union[a]	27	38	49	62
Option 3: 6% of Distribution Revenues by 2014	**Enbridge**	28	36	47	62
	Union	27	31	36	42

[a] Based on a 30% per year increase of budget components other that the low-income budget plus staff's estimate of the budget required to support the integration of low-income natural gas DSM with electricity CDM programs.

Table 3 below outlines staff's estimates of the required annual funding per customer for a subset of the natural gas utilities' rate classes. As illustrated in the table, between 2011 and 2014, the estimated average annual DSM funding per residential customer could remain the same as shown under Budget Option 1, or could increase from $6 to $22 for Enbridge's residential customers and from $9 to $22 for Union's residential customers under Budget Option 2. The funding increase under Budget Option 3 falls in-between the other two options, with the estimated average annual DSM funding per residential customer between 2011 and 2014 increasing from $6 to $14 for Enbridge's residential customers and from $9 to $14 for Union's customers. Staff notes that those estimated impacts would differ across customer rate classes, depending on the specific DSM budget allocated to each rate class. Staff also notes that the impact on individual customers within each rate class will depend on whether they are the recipients of DSM measures, among other things. Staff also notes that the estimated total bill impact would be less than 1% per year under all the proposed budget options.

Table 3 – Estimated Annual DSM Funding per Customer and Total Bill Impacts

Option 1: 0% DSM Budget Growth [a, c]

Utility	Service Area	Rate Class	Approved 2011	Option 1 2012	Option 1 2013	Option 1 2014
			Annual DSM Funding per Customer ($) / Total Bill Impact (%)			
Enbridge		Residential (R1)	$6 / N/A	$6 / 0.0%	$6 / 0.0%	$6 / 0.0%
		Commercial (R6)	$62 / N/A	$62 / 0.0%	$62 / 0.0%	$62 / 0.0%
Union	Northern and Eastern Operations	Residential (R01)	$9 / N/A	$9 / 0.0%	$9 / 0.0%	$9 / 0.0%
		Commercial (R10)	$477 / N/A	$477 / 0.0%	$477 / 0.0%	$477 / 0.0%
	Southern Operations	Residential (M1)	$9 / N/A	$9 / 0.0%	$9 / 0.0%	$9 / 0.0%
		Commercial (M2)	$224 / N/A	$224 / 0.0%	$224 / 0.0%	$224 / 0.0%

Option 2: Increased Focus on Deep Measures & Low-Income Program Integration with Electricity CDM [b, c]

Utility	Service Area	Rate Class	Approved 2011	Option 2 2012	Option 2 2013	Option 2 2014
			Annual DSM Funding per Customer ($) / Total Bill Impact (%)			
Enbridge		Residential (R1)	$6 / N/A	$14 / 0.8%	$18 / 0.4%	$22 / 0.5%
		Commercial (R6)	$62 / N/A	$80 / 0.2%	$104 / 0.3%	$135 / 0.4%
Union	Northern and Eastern Operations	Residential (R01)	$9 / N/A	$13 / 0.4%	$17 / 0.3%	$21 / 0.4%
		Commercial (R10)	$477 / N/A	$620 / 0.6%	$806 / 0.7%	$1048 / 0.9%
	Southern Operations	Residential (M1)	$9 / N/A	$14 / 0.5%	$17 / 0.4%	$22 / 0.5%
		Commercial (M2)	$224 / N/A	$291 / 0.4%	$378 / 0.5%	$491 / 0.6%

Option 3: Increase DSM budgets to about 6% of Distribution Revenues by 2014 [a, c]

			Approved	Option 3		
			2011	2012	2013	2014
Utility	**Service Area**	**Rate Class**	Annual DSM Funding per Customer ($) / Total Bill Impact (%)			
Enbridge		Residential (R1)	$6 / N/A	$8 / 0.2%	$11 / 0.3%	$14 / 0.3%
		Commercial (R6)	$62 / N/A	$80 / 0.2%	$104 / 0.3%	$135 / 0.4%
Union	Northern and Eastern Operations	Residential (R01)	$9 / N/A	$10 / 0.1%	$12 / 0.1%	$13 / 0.2%
		Commercial (R10)	$477 / N/A	$548 / 0.3%	$631 / 0.3%	$725 / 0.4%
	Southern Operations	Residential (M1)	$9 / N/A	$11 / 0.2%	$12 / 0.2%	$14 / 0.2%
		Commercial (M2)	$224 / N/A	$257 / 0.2%	$296 / 0.2%	$340 / 0.2%

[a] Assumes for simplicity that the proposed DSM budget levels will be allocated across rate classes in the same proportion that they are allocated under the natural gas utilities' Board-approved 2011 DSM plans.
[b] Assumes for simplicity that all of the low-income funding will be collected from the residential rate classes. Also assumes for simplicity that the remainder of the proposed DSM budget levels will be allocated across rate classes in the same proportion that they are allocated under the natural gas utilities' Board-approved 2011 DSM plans.
[c] The estimated bill impacts are based on estimated total bills that include the commodity cost of natural gas. For Enbridge, the total bill impacts are based on an annual consumption of 2,640 m^3 of natural gas for the R1 rate class and of 28,000 m^3 for the R6 rate class. For Union, the total bill impacts are based on an annual natural gas consumption of 2,600 m^3 for the R01 and M1 rate classes, 93,000 m^3 for the R10 rate class, and 73,000 m^3 for the M2 rate class.

3.7.1.4 Staff Recommendation

Staff notes, as described in section 3.7.1.1, that there were diametrically opposed views among participants on the recommended budget levels. In staff's view, the three proposed Budget Options provided reasonably reflect the wide spectrum of comments received. However, given the width of the range of options provided, staff finds it appropriate to recommend a Budget Option for participants' comments.

Staff notes that, assuming no alternative sources of funding for natural gas DSM activities undertaken by the natural gas utilities will be provided by other parties, such as the Ontario government, Budget Option 1 would not allow for an increased focus on deep DSM measures without leading to a reduction in the number of customers reached. In staff's view, the comments received were generally supportive of an increased focus on deep measures and none of those comments indicated that this should be supported by a reduction in the number of customers reached. Indeed, a number of comments noted the importance of providing equitable access to DSM programs among and across all rate classes to the extent reasonable, including access to low-income customers. Moreover, staff notes that most participants supported greater coordination of natural gas DSM and electricity CDM programs, or even the integration of some of those programs. In staff's view, the sum of those comments provide support for increasing the natural gas DSM budget levels and staff therefore does not recommend Budget Option 1.

Staff notes, however, that the Board may wish to consider the current level of cross-subsidization provided through DSM funding and determine whether any further increase would be appropriate at this time. Alternatively, other sources of funding, such as the Ontario government, could come forth and satisfy the staff's recommended DSM budget increase to support a greater focus on deep measures and greater coordination of natural gas DSM and electricity CDM programs, or even the integration of some of those programs. Both of these considerations, cross-subsidization level and other sources of funding, could call for Budget Option 1 over the other budget options outlined.

Staff notes that while environmental interest representatives supported DSM budget level increases beyond the CEA recommended range, such as would be the case under Budget Option 2, other participants recommended budget levels within or below the CEA recommended range. Accordingly, staff considers that Budget Option 2 would not be representative of the balance of comments received.

Staff recommends Budget Option 3. In staff's view, this option will allow the natural gas utilities to rationally increase their focus on deep measures while maintaining or increasing the number of participants reached. The DSM budget increases under this option should also provide some support to increase the level of coordination between natural gas DSM and electricity CDM programs. Integration of the low-income natural gas DSM with low-income electricity CDM programs under this option could still occur if additional sources of funding are provided and/or if there is a budget reallocation (i.e., increasing the low-income DSM budget while reducing other DSM budget components by a similar amount).

Staff's proposed DSM budget paths as outlined in Table 2 are targets. To increase or maintain their DSM budgets in accordance with those paths, the natural gas utilities would need to provide supporting evidence that they can cost effectively roll out those programs. Among other things, this evidence could be based on historical results of their DSM programs and market potential studies. Staff recommends that, if NRG wishes to undertake distribution-rate funded DSM activities, NRG consults with the intervenors in its most recent rate case to determine a DSM budget path proposal for Board approval.

In staff's view, the proposed target DSM budget paths shown in Table 2 would provide increased certainty to all involved in terms of funding and potential rate impact from one year to the next. Under staff recommended Option 3, for example, the year over year average annual funding increase per residential customer would range from about $2 to $3 for Enbridge's residential customers and from about $1 to $2 for Union's residential customers. Staff notes that, when taken alone, these estimated average increase in annual natural gas DSM funding per customer would not likely require any distribution rate impact mitigation.

Staff expects that the natural gas utilities would aim to remain on their DSM budget paths and that any annual spending beyond that would be accommodated through the DSM variance account ("DSMVA") option. Under the current DSM framework, the DSMVA "over-spend" option provide the natural gas utilities with the opportunity to spend and recover up to an additional 15% of their approved annual DSM budget, with all additional funding to be utilized on incremental program expenses only. As noted by the Board in its Phase I Decision in the generic proceeding (EB-2006-0021), this option "allow[s] utilities to aggressively pursue programs which prove to be very successful."

The natural gas utilities supported the continuation of the current 15% DSMVA "over-spend" option. One representative of ratepayer interests recommended that the "over-spend" option be lowered to 10% of the annual DSM budget "to reflect the increase in the magnitude of the DSM budgets that is expected to take place during the next DSM plan." The same representative commented that any amount spent beyond the annual DSM budget in one year could be deducted from the following year's DSM budget.

Staff recommends maintaining the 15% DSMVA "over-spend" option as it is under the current DSM framework in order to maintain the natural gas utilities' flexibility to aggressively pursue programs which prove to be very successful. Staff notes that budget flexibility will also be provided by the proposed funds re-allocation provisions described in section 3.3.1.

In staff's proposal, the overall DSM budget flexibility should be guided by expected funding levels for the three generic DSM program types. The continuation of separate budgets for each generic type of DSM program was supported by the natural gas utilities and other participants.

3.7.2 Budget for Resource Acquisition Programs

Enbridge and Union's comments indicated their expectation that the DSM budget share allocated to resource acquisition programs would decline over time due to, among other things, a refocus on market transformation and development programs.

As noted earlier, staff is not convinced that the new generic type of program proposed by the natural gas utilities (i.e., "development programs") should be created. Also as explained below, staff is proposing that the budget for market transformation programs be set at a level consistent with the approved 2011 level.

Staff expects that resource acquisition programs would maintain the largest share of the natural gas DSM budget and that its allocated budget should be sufficient to support the increase focus on deep measures while maintaining an equitable access to DSM programs among and across all rate classes, to the extent reasonable. Staff recommends that the natural gas utilities consult with their stakeholders to determine appropriate resource acquisition program budget levels over the term of the plan.

3.7.3 Budget for Low-Income Programs

Two participants recommended that the low-income DSM budget be increased consistent with the overall DSM budget. One low-income customer representative proposed that more than the current 14% share of the residential resource acquisition DSM budget be allocated to low-income DSM programs. The same representative proposed that separate line items be added to the low-income DSM budget "to include social housing and landlords/building owners with low-income residents in the private multi-unit rental market."

Staff is of the view that appropriate flexibility and guidance for the allocation of the low-income DSM budget among low-income customers will be provided by the adoption of the guiding principles outlined in section 3.3.2, inputs from the natural gas utilities' stakeholder engagement process, as well as the Board's review and approval process of the natural gas utilities' multi-year plan application. Staff is not convinced of the need to include additional budget line items within the low-income DSM budget in the DSM guidelines.

Staff notes that the Financial Package agreement that forms part of the current DSM framework, as reflected in the Phase I Decision in EB-2006-0021, provides guidance on the two components of the low-income DSM budgets. The first is that a minimum of 14% of the market transformation program budget should be targeted to low-income consumers. The second is that a minimum of $1.3 million or 14% of each respective natural gas utility's resource acquisition residential DSM program budget should be targeted to low-income consumers, whichever is greater. The Financial Package agreement also indicates that:

> The Utilities agree that by the establishment of this spending level floor, they will not, as a result, reduce planned DSM spending in other rate classes or sectors which are directed at low-income residents (e.g. social housing multi-unit residential spending) or their spending on fuel switching targeted to low-income customers.

As described in the Phase I Decision, the basis for the 14% share was "to ensure that low-income consumers have access to DSM programs at least in approximate proportion to their percentage of residential revenue." Staff proposes that the natural gas utilities submit an update of those shares as part of their multi-year DSM plan application for information purposes.

Staff notes that the natural gas utilities' approved amendments to their 2011 low-income weatherization plan were developed through extensive consultation with stakeholders. A number of those stakeholders indicated that because Enbridge and Union's 2011 low-income weatherization budget amendments were developed in the context of the current DSM framework, their support for the approval of those amendments should not necessarily be indicative of their preferred approach under a new DSM framework. Accordingly, staff recommends that the natural gas utilities consult with their stakeholders to determine appropriate low-income DSM budget levels over the term of the plan. Staff expects those consultations to consider the degree to which coordination and/or integration of low-income natural gas DSM programs with low-income electricity CDM programs is warranted at this time, as well as consider the low-income natural gas DSM budget level required to support that recommendation.

3.7.4 Budget for Market Transformation Programs

The natural gas utilities' comments suggested that market transformation programs should comprise a larger share of their DSM budget over time. As noted earlier, two participants supported the introduction of development programs, some of which would, in staff's view, fall within the market transformation program category. Staff notes that in comments received at an earlier stage of this consultation and prior to the issuance of the CEA report, representatives of ratepayer interests identified market transformation as an "outdated" concept, mainly due to the many players with programs in the field of energy conservation that make it difficult, if not impossible, to attribute causation. Also in earlier comments, representatives of environmental interests called for further clarity in terms of metrics measuring market transformation activities with more emphasis on lost opportunity markets rather than education and training activities.

Staff notes that market transformation programs are focused on facilitating fundamental changes that lend to greater market shares of energy-efficient products and services, and on influencing consumer behaviour and attitudes that support reduction in natural gas consumption. They are designed to make a permanent change in the marketplace over a long period of time. These programs include a wide variety of different approaches. For example, such program approaches include offering conferences and tradeshows for building contractors; radio advertising targeted to natural gas customers encouraging them to reduce energy consumption by installing more energy efficiency space heating; and education materials distributed to schools to teach children about saving energy and protecting the environment.

In staff's view, market transformation programs tend to be more applicable to lost opportunity markets where, for example, equipment is being replaced or new buildings are being built. Lost opportunity markets refer to DSM opportunities that, if not undertaken during the current planning period, will no longer be available or will be substantially more expensive to implement in a subsequent planning period. An example of preventing a lost DSM opportunity would be incorporating drain heat water recovery systems in new buildings, the cost of which is much higher in existing buildings. Another example may be to improve the thermal envelope of a building at the time the building is undergoing unrelated major renovation work.

It can be rather difficult to provide definitive evidence that the market transformation programs are responsible for the reported results. In comparison, resource acquisition programs seek to achieve direct, measurable savings customer-by-customer. Staff notes that some programs are a mix of market transformation and resource acquisition programs and seek both outcomes – fundamental changes in markets and direct, measurable energy savings.

Staff is of the view that DSM activities funded through regulated rates should be limited to niches within the realm of market transformation programs where competitive forces are not expected to yield the results sought or not within an acceptable timeline. In staff's view, therefore, the natural gas utilities can help fill in some of the gaps in achieving market transformation results or accelerate the achievement of those results, but should otherwise limit their participation in this type of program. Moreover, staff recommends that market transformation programs be focused on lost opportunities and be outcome-based (e.g., selected and designed to achieve measurable impacts on the market) as opposed to output-based (e.g., delivering a given number of workshops).

Staff notes that Enbridge's approved 2011 budget for market transformation programs of $5.132 million includes $2.762 million for low-income weatherization which staff considers inconsistent with the definition provided above for this generic type of programs. Accordingly, staff views Enbridge's "base" 2011 approved market transformation budget to be $2.37 million. Union's approved 2011 market transformation budget is $1.464 million. Staff recommends that the natural gas utilities consult with their stakeholders to determine appropriate market transformation program budget levels over the term of the plan.

3.7.5 Budget for Evaluation, Monitoring, and Verification

CEA recommended and participants agreed that the Board should consider more extensive review of those programs that account for the majority of expenditures and savings. Staff also finds this proposal reasonable.

CEA also proposed that a maximum budget for evaluation, monitoring and verification ("EM&V") be established within a range of 3 to 5% of the total DSM budget. The natural gas utilities and a ratepayer representative were supportive of that range, while two other participants objected to it.

In staff's view, there is no evidence that the current or expected EM&V spending by the Ontario natural gas utilities may be excessive. Staff notes that EM&V needs will change from year to year depending on the nature of the DSM programs undertaken and that "flexibility" is a recurring theme for the proposed framework. Accordingly, staff considers that it would not be in the public interest to set a cap on the EM&V budget. Staff proposes that the natural gas utilities, as informed through their stakeholder engagement process, remain responsible for determining the appropriate EM&V requirements and the ensuing budget.

3.8 Metrics

Metrics refer to standard of measurements used to assess the results of DSM programs. For example, cubic meters (m^3) of natural gas saved could be used as a metric to determine the impact of a DSM program.

3.8.1 Resource Acquisition Programs

CEA recommended that the Board adopt market penetration of the best available technologies (“BAT”) as its primary metric for evaluating whether a particular DSM program or measure is successful. In situations where market penetration is not applicable or cannot be measured, CEA recommended using reduction in natural gas consumption per customer as the metric.

Most participants expressed concerns with using market penetration of BAT as the primary metric. Those concerns included the cost involved in setting baselines for all BATs, the difficulty to determine what constitutes “BAT” at a given point in time as well as the need to reassess what “BAT” is over time, and the fact that BAT may not be applicable to custom projects and that custom projects comprise a large share of the DSM budget.

A number of participants proposed alternative primary metrics. The natural gas utilities proposed using either net societal savings or cubic meters of natural gas and water savings over the life of the measures. Three other participants proposed using the incremental reduction in normalized average use per customer (“NAUC”) resulting from the DSM programs. One participant suggested tracking reduction in GHG emissions as an alternative.

Staff notes that there was little support among participants to maintain TRC savings as the primary metric. Staff also notes that CEA expressed the view that “TRC net savings is difficult to measure and verify, and may have contributed to the development of shallow DSM programs in Ontario (that is, programs with modest energy savings or a short-term focus).” Staff notes that there was also little support among participants to use BAT instead. With respect to using NAUC metric, staff is concerned with the difficulty and controversy that may surround this measure in light of the findings in the PEG report.

Staff agrees with CEA’s view that, to the extent possible, DSM metrics should be straightforward and verifiable. Staff however notes that this objective must be balanced against the goal of providing signals consistent with the four guiding principles outlined earlier in section 3.3.1:

- Maximization of cost effective natural gas savings;

- Provision of equitable access to DSM programs among and across all rate classes, to the extent reasonable, including access to low-income customers;
- Prevention of lost opportunities; and
- Pursuit of deep energy savings.

Staff is of the view that the experience gained from the current DSM framework highlights the risk of using a single metric to drive multiple objectives (e.g., the focus on “shallow” DSM programs such as deployment of energy efficient showerheads and faucet aerators). Staff proposes to use a scorecard approach for resource acquisition programs that would include:

- Cubic meters (m^3) of natural gas saved;
- $ spent per m^3 of natural gas saved; and
- Number of participants that receive at least one deep measure.[49]

The natural gas utilities, as informed through their stakeholder engagement process, would propose the weight associated with each metric and may propose additional metrics. However, staff does not recommend the inclusion of a TRC or societal net savings metric; staff recommends using a metric based on m^3 of natural gas saved instead.

Staff considers that m^3 savings of natural gas is intuitively better aligned with the nature of natural gas utilities' business and it is consistent with the metrics in the electricity CDM code (i.e., electricity and peak electricity demand savings). Staff does not recommend adding a metric based on reduction of GHG emissions, but notes that this metric would strongly, if not perfectly, correlate with m^3 savings of natural gas.

Staff notes that, under a budget constraint, rewarding the highest level of natural gas savings and going beyond a target deployment of deep measures will drive cost efficiency. However, Staff is of the view that having an explicit cost-efficiency measure, such as the proposed $ spent per m^3 of natural gas saved, will provide greater transparency to all interested participants and the Board. Board staff also expects that setting explicit cost efficiency targets will allow the Board and interested participants, including the natural gas utilities, to better guide the development of the multi-year DSM plan and to optimize value for money from the first to the last DSM dollar spent.

Staff notes that, to maintain equitable access to DSM programs among and across all rate classes to the extent reasonable, some programs within the portfolio of resource acquisition programs may have to be “shallower” in nature. “Shallower” programs, such as thermostat replacements, are less costly than

[49] An agreed upon list of what constitutes “one deep measure” could include increase in insulation in more than half of the walls, basement walls, or the attic of the home.

deep measures, such as improving wall insulation, and can therefore be offered to a larger number of participants for a given budget amount.

3.8.2 Low-Income Programs

Most participants agreed that low-income programs should be evaluated using a scorecard approach. Staff agrees since, as noted by some participants, a scorecard approach can help promote and strengthen the benefits of certain aspects of the low-income DSM programs.

Staff proposes that scorecard(s) for low-income program include:

- m^3 savings of natural gas;
- $ spent per m^3 of natural gas saved; and
- Number of participants that receive at least one deep measure.[50]

The natural gas utilities, as informed through their stakeholder engagement process, would propose the weight associated with each metric and may propose additional metrics.

Staff notes that, under a budget constraint, rewarding the highest level of natural gas savings and going beyond a target deployment of deep measures will drive cost efficiency. However, staff is of the view that having an explicit cost-efficiency measure, such as the proposed $ spent per m^3 of natural gas saved, will provide greater transparency to all interested participants and the Board. Board staff also expects that setting explicit cost efficiency targets will allow the Board and interested participants, including the natural gas utilities, to better guide the development of the multi-year DSM plan and to optimize value for money from the first to the last DSM dollar spent.

Staff notes that, to maintain equitable access to DSM programs among low-income customers to the extent reasonable, some programs within the portfolio of low-income programs may have to be “shallower” in nature. “Shallower” programs, such as thermostat replacements, are less costly than deep measures, such as improving wall insulation, and can therefore be offered to a larger number of participants for a given budget amount.

[50] Ibid.

3.8.3 Market Transformation Programs

Most participants agreed that market transformation programs should be evaluated using a scorecard approach. Staff agrees and is of the view that a scorecard approach has been demonstrated to be a practical approach to measuring the impact of market transformation programs.

Staff proposes that, to the extent possible and practical, scorecard(s) include m^3 savings of natural gas, along with a $ spent per m^3 of natural gas saved. Depending on the type of market transformation programs, other outcome based metrics should be proposed for inclusion on the scorecard(s) by the natural gas utilities, taking into account inputs gathered through their stakeholder engagement process. As an example, metrics should include some quantitative and qualitative outcome-based results such as the extent to which lost opportunities are captured, increase in market penetration of specific measures, increase in education and awareness, and equitable access to programs to the extent reasonable.

3.9 Targets

A target refers to the level against which the actual result of a DSM program will be assessed. The target level can be set at the metric level (e.g., saving 100,000 m^3 of natural gas) and at the scorecard level (e.g., achieving a weighted score of the scorecard metrics of 100%).

3.9.1 Resource Acquisition Programs

CEA and representatives of ratepayer interests recommended that the targets be "aggressive and challenging" for the natural gas utilities. One of those representatives proposed that the targets should be established at the rate class level. In contrast, the natural gas utilities recommended replacing the existing TRC net saving targets with a linear incentive payment mechanism starting at the first unit of savings. One environmental interest representative seemed to support the natural gas utilities' proposal noting that not providing an incentive for achievements below the target would likely result in "timid" targets.

Staff notes that the approach proposed by the natural gas utilities was opposed by a number of ratepayer representatives and one environmental interest representative. Staff is of the view that linking incentive payments to the achievement of targets is an important part of establishing a framework that is broadly supported by participants.

Staff recommends that the targets for the metrics discussed above for resource acquisition programs be developed by the natural gas utilities, taking into account inputs gathered through their stakeholder engagement process. Consistent with the current approach used by Enbridge and Union, three levels of achievement should be provided on the scorecard for each metric: one at 50%, 100% and 150%. Staff also recommends that the natural gas utilities file evidence on the challenges they will face in meeting each of these three scorecard levels.

3.9.2 Low-Income Programs

Targets and metrics for low-income programs should be developed by the natural gas utilities, as informed through their stakeholder engagement process, and should be submitted for approval by the Board as part of the multi-year plan application. Consistent with the current approach used by Enbridge and Union, three levels of achievement should be provided on the scorecard for each metric: one at 50%, 100% and 150%. Staff also recommends that the natural gas utilities file evidence on the challenges they will face in meeting each of these three scorecard levels.

3.9.3 Market Transformation Programs

Targets and metrics for market transformation programs should be developed by the natural gas utilities, as informed through their stakeholder engagement process, and should be submitted for approval by the Board as part of the multi-year plan application. Consistent with the current approach used by Enbridge and Union, three levels of achievement should be provided on the scorecard for each metric: one at 50%, 100% and 150%. Staff also recommends that the natural gas utilities file evidence on the challenges they will face in meeting each of these three scorecard levels.

3.10 Incentive Payments

According to CEA's jurisdictional review, only one of the five other Canadian provinces surveyed offered incentive payments. CEA also found that eight of the twelve U.S. states reviewed offered "incentives for exceptional program performance," three of which also imposed penalties for poor performance. Of the three other countries surveyed, none offered incentive payments, although one did impose penalties for poor performance.

A number of participants representing ratepayer representatives were of the view that a shareholder financial incentive is not required. One of these participants commented that "there seems to be an imbalance when EGD spends $20 million of ratepayer money and receives over $8 million as a payment to its shareholder, while at the same time being compensated for lost revenue." Another representative of ratepayer interests proposed that the maximum incentive be capped at 10% of the approved DSM budget. In contrast, one participant representing environmental interests argued that there should be no cap on the level of DSM shareholder incentives because "it should always be in a utility's financial self-interest to achieve additional cost-effective DSM savings."

In the event that a shareholder financial incentive is considered, participants representing ratepayer interests agreed with CEA's view that no incentive should be provided for performance below 100% of the target. The natural gas utilities disagreed with meeting 100% of the target being a pre-condition for a shareholder incentive payment arguing that it "will discourage efforts focusing on longer term opportunities that may have an element of risk associated with the first years." One participant representing environmental interests also objected to the "100% of target" requirement for an incentive payment, arguing that it may result in "timid" targets.

Staff notes that the Board determined in its E.B.O. 169-III Report of the Board dated July 23, 1993 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." In addition with the underlying return for DSM activities set consistent with other distribution activities, the Board noted in its Decision in Enbridge's 2006 rate case (EB-2005-0001, EB-2005-0437) that:

> The Shared Savings mechanism is designed to provide an incentive to the utility to aggressively pursue DSM savings. The existing SSM mechanism for the Company was initiated in 1999. The theory behind the incentive was to reward achievement of the TRC goal. Revenue flowed to the shareholder as results surpassed the forecast incentive threshold or pivot point. No payout to the shareholder was made when results fell short of the TRC target.

Later in the same Decision, the Board agreed to allow for the incentive payment to begin at 75% instead of 100%, but also noted that "The core purpose of the mechanism is to incentivize the Company to achieve and surpass the established TRC target. It is a reward for exemplary performance, not a payout for any performance, no matter how meagre."

Staff considers that an appropriate amount should be available to provide an incentive to the natural gas utilities to achieve or surpass the targets. Staff notes that in its June 22, 2010 Notice of Proposal to Issue the electricity CDM Code, the Board indicated that "The amount of [incentive] funds available is proportional to that which is available to the gas distributors that undertake Demand Side Management ('DSM') activities and achieve 150% of their DSM targets."

Staff therefore proposes that the maximum incentive amount for Enbridge and Union remain consistent with their current level.[51] More specifically, staff proposes that $9.5 million be the maximum incentive amount available for the 2012 program year, to be escalated for inflation to determine the subsequent program year caps (the "Annual Cap").[52] This will result in the Annual Cap representing a decreasing proportion of the DSM budgets since, under the recommended Budget Option 3, the latter will increase at 30% per year for Enbridge and 15% per year for Union, both which are greater than the Bank of Canada's target annual 2% inflation rate. Staff views the decreasing proportion of the Annual Cap as responsive to participants' comments that the total incentive amount may have been more than sufficient. Staff's proposal also provides consistency with the electricity CDM Code and continuity with the approach underlying the current DSM framework.

Staff recommends that, if NRG wishes to undertake distribution-rate funded DSM activities, NRG consults with all the intervenors in its most recent rate case to determine whether any incentive amount is required and, if so, what the appropriate level should be.

To the extent that the *approved* DSM budgets deviate in magnitude from the proposed budget path outlined in the Final DSM Guidelines, the Annual Cap should be scaled accordingly.[53] This will help ensure that the eligible incentive amount is consistent with the expected level of efforts require to achieve or exceed the approved targets. For greater clarity, and as implied by the proposed metrics outlined in section 3.8, the natural gas utilities will have an incentive to contain their *actual* costs while striving to achieve or exceed their targets; the proposed Annual Cap adjustment relates to the *approved* DSM budgets as opposed to actual expenditures.

Staff proposes that the maximum annual incentive amount available to market transformation programs be set at 5% of the Annual Cap, which would provide continuity and consistency with the amount available under the current DSM framework. Staff suggests that the remaining 95% of the Annual Cap be allocated between resource acquisition and low-income programs based on their approved DSM budget shares.

[51] Under the current framework, the maximum incentive amount for each gas utility for the 2011 program year is $9.4 million. This amount is comprised of the 2007 $8.5 million incentive cap for TRC based results and $0.5 million for market transformation programs, both of which have been escalated for inflation since 2007.

[52] More specifically, the Annual Cap would be escalated using the Ontario Consumer Price Index as determined in October of the preceding year (i.e., the 2013 cap will increase based on CPI as determined at October of 2012).

[53] For instance, if the approved DSM budget is 25% less in a given year than the target budget path as shown in Table 2 under Option 3, the maximum incentive amount for that year will be reduced by 25%.

Under staff's proposal, performance for all three types of programs (i.e., resource acquisition, low-income, and market transformation) will be evaluated using balanced scorecards. Staff recommends continuing the current approach for scorecards whereby targets at 50%, 100% and 150% are established for each metric on the scorecards. Under staff's proposal, no incentive would be provided for achieving a scorecard weighted score of less than 50%. For each metric on the scorecard(s), results will be linearly interpolated between 50% and 100%, as well as between 100% and 150%. Metric results below 50% will be interpolated using the 50% and 100% targets, and metric results above 150% will be interpolated using the 100% and 150% targets.[54]

Staff also proposes to introduce a pivot point at the 100% level. More specifically, to encourage performance beyond the 100% target level, staff proposes that 40% of the incentive available be provided for performance achieving the 100% level, with the remaining 60% available for performance at the 150% level.[55] As indicated previously, staff recommends that the 100% target level be set to be appropriately challenging for the natural gas utilities to meet. The incentive amount would be capped at the scorecard weighted score of 150%.

Two participants representing ratepayer interests recommended that penalties be imposed for failing to achieve a threshold level (e.g., 75% of the target). Another participant, also representing ratepayer interests, disagreed and suggested instead that repeated failure to meet the targets should result in a review of the framework. Staff is not proposing that penalties be added to the framework at this time. Staff is of the view that offering no incentive for performance falling below established levels as discussed above will provide a sufficient signal that such performance levels should be avoided.

---

[54] For example, if the 50%, 100% and 150% targets are 40 units, 60 units and 70 units respectively, then a result of 10 units would imply a metric score of -25%.

i.e., $50\% - \frac{(100\% - 50\%)}{(60 - 40)} * (40 - 10) = -25\%$

A result of 80 units would imply a metric score of 200%.

i.e., $150\% - \frac{(150\% - 100\%)}{(70 - 60)} * (70 - 80) = 200\%$

[55] For example, if the maximum incentive available is $1 million, the incentive payment will be $400,000 if the weighted scorecard result is 100%, and $1 million if the weighted scorecard result is 150% or above. As results are to be linearly interpolated, a weighted scorecard result of 75% would lead to an incentive payment of $200,000.

i.e., $\$400{,}000 * \frac{(75\% - 50\%)}{(100\% - 50\%)} = \$200{,}000$

A weighted scorecard result of 125% would lead to an incentive payment of $700,000.

i.e., $\$400{,}00 + \$600{,}000 * \frac{(125\% - 100\%)}{(150\% - 100\%)} = \$700{,}000$

3.11 Lost Revenue Adjustment Mechanism ("LRAM")

Most participants supported the continued LRAM approach set out in the current DSM framework. Staff agrees, with one exception.

Staff recommends that Union adopts Enbridge's approach whereby the annual impact for the first year of the DSM programs is calculated on a monthly basis based on the volumetric impact of measures implemented in that month multiplied by the distribution rate for each of the rate classes that the volumetric variance occurred in. Union's current approach is to calculate the annual impact for the first year of the DSM programs as 50% of the annual volumetric impact multiplied by the distribution rate for each of the rate classes that the volumetric variance occurred in. Besides providing a consistent LRAM methodology across the natural gas utilities, staff is of the view that aligning Union's approach with Enbridge's will help ensure that LRAM amounts more closely reflect the actual timing of the implementation of the DSM measures.

3.12 Program Evaluation and Audit

CEA recommended that the Board appoint the entities responsible for conducting the independent program evaluation and the third-party audit of program results. A number of participants representing environmental interests as well as one ratepayer interest representative agreed with CEA's recommendation. However, the natural gas utilities and a number of other participants objected to this recommendation. Another participant proposed that the oversight of the audit should fall under the Evaluation and Audit Committee ("EAC").

Staff notes that the views expressed by participants seemed to indicate that, among those who did not support the current approach to program evaluation and the ensuing audit of program results, there appeared to be greater concerns with the current audit approach than with the program evaluation. Staff's proposal regarding program evaluation and the audit approach are outlined below.

Under staff's proposal, the natural gas utilities would remain responsible for the evaluation of program results. The stakeholder engagement process would be the formal channel for stakeholders to engage in the development of an evaluation plan and budget, and to review the evaluation results as they become available over the term of the plan. The stakeholder engagement process could build upon the current framework whereby all interested stakeholders can participate in meetings to be held at least twice a year (the "Consultative" meetings, as per the current DSM framework's terminology) with a sub-committee to represent members of the full "Consultative" to provide ongoing advice to the natural gas utility on various aspects of its DSM plan (e.g., an Evaluation and Audit Committee ("EAC")). Staff recommends that, at a minimum, the stakeholder engagement process include two meetings every year where all participants in the Board's consultation on the development of the gas DSM guidelines (EB-2008-0346) would be invited to participate. The stakeholder engagement process should be proposed by the natural gas utilities, in consultation with its stakeholders, as part of their multi-year DSM plan application.

Staff proposes that all program evaluations would need to be conducted by a third-party evaluator. The natural gas utilities' third-party evaluator(s) should, to the extent possible, be selected from the OPA's third-party vendor of record list. Staff also proposes that the natural gas utilities' third-party evaluators should seek to follow the OPA's evaluation, measurement and verification protocols, where applicable and relevant to the natural gas sector. [56]

With regard to the audit of third-party evaluated program results, staff proposes to maintain the current approach whereby the natural gas utilities have the oversight of the audit process and the stakeholder engagement process provides an advisory role. Staff notes that one of the main concerns raised with the current audit process seems to have arisen from an incident outlined in a letter from the School Energy Coalition ("SEC") dated September 3, 2009. In its letter, SEC notes that Enbridge appears to have unilaterally excluded their 2007 auditor from the list of eligible bidders for the audit of the 2008 results and over the objections of EAC members. SEC commented that "This calls into question the integrity of the selection process, and therefore the independence of the audit."[57] By letter dated September 16, 2009, Enbridge responded that they intended to "ensur[e] this does not happen again by strengthening our internal review and communication processes."[58]

Staff expects that the experience learned from this incident will help prevent its reoccurrence. While participants have noted other concerns with the current approach[59], it may nonetheless be that maintaining the current audit approach is the preferred alternative.

[56] The OPA's evaluation, measurement and evaluation documents can be found on the OPA's website at:
http://archive.powerauthority.on.ca/Page.asp?PageID=122&ContentID=6484&SiteNodeID=404

[57] This letter was included in Enbridge's application to clear its DSM variance accounts balances for the 2008 program year. See Exhibit B, Tab 5, Schedule 1 of the Enbridge's application dated October 7, 2009 in Board file No. EB-2009-0341.

[58] See Exhibit B, Tab 5, Schedule 1, page 3 of 3 of the Enbridge's application dated October 7, 2009 in Board file No. EB-2009-0341.

[59] For instance, one participant argued that:

> The reality that the utilities currently control interaction with evaluation contractors, see draft reports that the EACs do not always see, and control the timing of release of final reports also continues to keep stakeholders from fully trusting the evaluation process.

Building on the current audit approach, staff proposes that one member of Board staff be invited to attend the stakeholder engagement meetings, including any subcommittee meetings, as an observer to gain a better understanding of the issues as they arise, such as with the selection of the auditor. Staff notes that, under the current DSM framework, Board staff already attends as an observer meetings of the Consultatives, but has not attended EAC meetings.

3.13 Filing and Reporting Requirements

One ratepayer representative expressed the view that "with the advent of Market Transformation and Low Income Programs additional reporting requirements are necessary." Two other ratepayer representatives and one environmental interest representative were of the view that the reporting requirements outlined in the initial draft DSM guidelines issued on January 26, 2009 would be appropriate. Two other participants argued that the "Annual Report" described in section 9.0 of those initial draft DSM guidelines would be unnecessary since this information is already provided in other regular natural gas DSM filings.[60] Enbridge proposed that, in addition to continuing those regular natural gas DSM filings, it may file mid-term updates within a multi-year plan where it could seek approval for new resource acquisition programs or measures, update underlying resource acquisition program assumptions, and propose a change in metrics for scorecard-based programs.

Staff supports the views expressed by some stakeholders that there are sufficient reporting channels in place to gather an appropriate level of information; a new and separate "Annual Report" is not required. Staff however sees merit in clarifying some of the required information to be contained in the Evaluation Report, such as the inclusion of the verification studies, and has provided this guidance in the Revised Draft DSM Guidelines.

---

[60] These are:

- The multi-year gas DSM plan and annual gas DSM plan (as applicable);
- The annual filing in accordance with the requirement set out in section 2.1.12 of the Board's *Natural Gas Reporting & Record Keeping Requirements (RRR) Rule for Gas Utilities*.
  - To fulfill this requirement, the gas utilities have filed the final report of the auditor (a.k.a. the audit report), which sets out the result of the third party audit conducted on the gas utility's Evaluation Report (a.k.a. the draft annual report).
- The application for input assumption updates based on the result of the evaluation and audit process from the preceding program year; and
- The annual application for clearance of DSM account balances (i.e., the LRAM account, an account related to the incentive amounts, and the DSM variance account).
  - This application includes the following documents: the Evaluation Report (a.k.a. the draft annual report) or the audited Evaluation Report (a.k.a., the (final) annual report), the auditor's final report on the Evaluation Report (a.k.a. the audit report), the EAC Audit Summary Report, and information setting out the allocation of DSM variance account balances across rate classes.

In respect of Enbridge's proposal to file mid-term updates as required during the plan term, staff is of the view that it is consistent with and supports the flexibility envisaged for the new DSM framework. Indeed, as discussed earlier, staff proposes that the natural gas utilities be required to apply for Board approval when cumulative fund transfers among Board-approved programs exceed 30% of the approved annual budget for an individual natural gas DSM program. Under staff's proposal, natural gas utilities would also be required to seek approval to re-allocate funds to new programs that are not part of the natural gas utility's Board-approved DSM plan.

Staff proposes to rename the account associated with the incentive payments[61] the "DSM Incentive Deferral Account" to better reflect the nature of this account under the proposed new DSM framework. Otherwise, accounting treatment and reporting of DSM costs remain consistent with the existing Reporting and Record Keeping Requirements for natural gas utilities.

The Revised Draft DSM Guidelines set out the minimum filing and reporting requirements for the multi-year natural gas DSM plan, input assumption updates, LRAM and incentive amounts, and disposition of any balance in the DSM variance account. The natural gas utilities are expected to follow the filing and reporting requirements outlined in the Revised Draft DSM Guidelines as a minimum. The natural gas utilities in all cases are responsible for ensuring that all relevant information is before the Board.

3.14 Stakeholder Input and Consultation Process

While the natural gas utilities as well as a ratepayer representative were of the view that the current approach to solicit stakeholder input is appropriate, some participants proposed options to build and expand upon this approach. In contrast, one participant representing environmental interests commented that the current approach has been "cumbersome, expensive and not very effective."

As noted before, staff agrees with the view that the natural gas utilities are ultimately responsible and accountable for their DSM activities. The proposed natural gas DSM framework is intended to provide greater clarity in respect of the natural gas utilities' responsibilities, accountability measures and available incentive amounts. So, while consultative activities should be undertaken at the discretion of natural gas utilities, it is expected that this discretion will be guided by the overall DSM framework. In addition to the guidance embedded in the overall DSM framework, staff recommends continuing the minimum twice a year "Consultative" meetings where all participants in the Board's consultation on the development of the gas DSM guidelines (EB-2008-0346) would be invited to participate.

[61] This account has typically been referred to under the current DSM framework as the Shared Savings Mechanism Variance Account.

Staff notes that the comments received provided support for the development of new terms of reference ("ToR") for the current DSM framework's Consultative and EAC. In particular, the natural gas utilities, which are of the view that the current consultation process is appropriate, supported the development of new ToR for their Consultative and EAC. Staff agrees that new ToR for the stakeholder engagement process should be developed by the natural gas utilities in cooperation with their stakeholders and submitted to the Board as part of their respective multi-year DSM plan application. These ToR should build upon experience to date and should reflect, to the extent possible, consensus views of the natural gas utility and its stakeholders. Also, as indicated in section 3.12, the ToR could clarify that Board staff may attend, as an observer, stakeholder engagement meetings, including any subcommittee meetings.

3.15 Coordination and Integration of Natural Gas and Electricity Conservation Programs

Most participants supported greater coordination of natural gas DSM and electricity CDM programs, or even the integration of those programs. Two participants argued that a third party administrator would facilitate the integration of natural gas and electricity conservation programs. Three ratepayer representatives noted the importance of attribution rules in promoting coordination and integration while ensuring fairness in terms of sources of ratepayer funding. One ratepayer representative disagreed, arguing that pre-conditions should occur before considering any type of integration including "[local electricity distributors] gaining more experience with CDM, further consolidation of the electricity distributors, and integration of new renewable resources into distribution systems."

Staff agrees with the view that greater coordination and integration of certain electricity and natural gas conservation programs could result in efficiency gains, thereby increasing total natural gas savings achievable at a given budget level. Staff notes that in his July 5, 2010 letter, the Minister indicated his support for the for "co-ordinated efforts" for low-income natural gas DSM and electricity CDM programs. Staff also notes the ECO's comments that:

> the government, electric and gas utilities, and the Ontario Power Authority are all active in the residential sector. Given the high delivery costs associated with delivering conservation programs in this sector, there is a need for a coordinated approach that can address both gas and electricity savings.[62]

[62] *Re-thinking Energy Conservation in Ontario – Results, Annual Energy Conservation Progress Report – 2009 (Volume Two)*, released on November 30, 2010, p. 41.

While staff supports greater coordination or integration of natural gas DSM and electricity CDM programs, staff believes this should be encouraged, as opposed to mandated as suggested by one environmental interest representative. Staff is of the view that the proposed natural gas DSM framework outlined in the Revised Draft DSM Guidelines provides adequate flexibility and incentives to drive a rational coordination or integration of natural gas and electricity conservation programs. In that regard, staff expects the natural gas utilities in consultation with stakeholders to design a proposed multi-year natural gas DSM plan that will reflect this objective.

This page has been left blank intentionally

4. Next Steps

Interested participants are invited to provide written comments by February 14, 2011 on the options and recommendations contained in this Staff Discussion Paper and on the Revised Draft DSM Guidelines shown in Appendix A.

Informed by this Staff Discussion Paper, the Revised Draft DSM Guidelines and participants' written comments, the Board will make any revisions to the Revised Draft DSM Guidelines that it finds appropriate and anticipates issuing its Final DSM Guidelines in April 2011.

The Board expects that the natural gas utilities will file their multi-year DSM plans for the 2012 program year and beyond in accordance with the Board's DSM Guidelines.