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ENBRIDGE

February 20, 2009

VIA RESS, EMAIL and Courier

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

Re: Ontario Energy Board (the "Board") File No.: EB-2008-0346
Comments of Enbridge Gas Distribution Inc. ("Enbridge") on the Draft Demand Side Management ("DSM") Guidelines for Natural Gas Distributors

Board Staff issued for comment the draft Demand Side Management Guidelines for Natural Gas Distributors ("the draft guidelines") on January 26 2009, attached are the comments of Enbridge.

To assist the Board Enbridge has engaged two 3rd party industry experts to provide objective comments on the draft Demand Side Management Guidelines. These independent expert assessments are attached to the submission.

Enbridge and Union Gas have worked collaboratively to provide alignment on all areas of the guidelines, with the exception of section 5.1.1. Even though the utility specific details related to section 5.1.1 are different, many of the principles that underlie both models are similar.

Please find attached the submissions of Enbridge:

- Appendix A - affidavit of Dr. Violette
- Appendix B – IndEco Review of Draft DSM Guidelines for Natural Gas Distributors
- Appendix C – revised, blacklined draft Demand Side Management Guidelines for Natural Gas Distributors
- Appendix D – revised draft Demand Side Management Guidelines for Natural Gas Distributors (clean line)

Please contact the undersigned if you have any questions.

Sincerely,

S.L.Spratt for

Bonnie Jean Adams
Regulatory Coordinator

cc: EB-2008-0346 Intervenors
Mr. D. O'Leary, Aird & Berlis (via email)

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF a Consultation on the Development of Guidelines for Demand Side Management to be used by Natural Gas Distributors

**SUBMISSIONS OF
ENBRIDGE GAS DISTRIBUTION INC.**

Introduction

1. This is the submission of Enbridge Gas Distribution Inc. ("EGDI" or the "Company") in response to "Board Staff's Discussion Paper Draft DSM Guidelines for National Gas Distributors" (the "Paper") and the "Draft DSM Guidelines for National Gas Distributors" (the "Draft Guidelines"), both dated January 26, 2009.

Format of Submission

2. This submission is formatted into several parts. This first part contains EGDI's specific submissions to the Paper and Draft Guidelines. EGDI has not made a detailed submission in respect of every subsection of the Draft Guidelines in that, in a number of instances, it appears that Board Staff are proposing the continuance of the status quo, being rules and methodologies approved by the Ontario Energy Board ("OEB" or "Board") in the DSM Generic Proceeding (EB-2006-0021)[1] (the "Generic Proceeding"). Where EGDI has not made detailed or any submissions in respect of a specific subsection in the Draft Guidelines, such silence should be interpreted as EGDI's support for the continuation of the status quo which the Company submits has worked as contemplated and for which no

[1] DSM Generic Proceeding, EB-2006-0021, Decision with Reasons dated August 25, 2006.

change is required. If unexpectedly the contrary is alleged by a stakeholder, EGDI reserves the right to respond with a further brief submission.

3. In certain circumstances, EGDI has either deferred or limited its comments given the relevance of a decision which is pending from the OEB in a related matter. For example, the Board's decision arising from the Low Income Consultative could have implications in respect of those sections of the Draft Guidelines which impact low income consumers. Another is the Ontario *Green Energy Act*, which is expected to be released shortly. As a result, EGDI reserves its right to file additional submissions which may request changes to the Draft Guidelines as a result of these initiatives.

4. In other instances, EGDI's submission may only suggest amendments to the Draft Guidelines which provide greater certainty or clarity and for which it is believed that additional submissions beyond recognizing this need are not required.

5. It should be noted that EGDI retained Daniel M. Violette, Ph.D., to assist with its review of the Paper and Draft Guidelines. It will be recalled that Dr. Violette appeared as an expert witness at the Generic Proceeding and provided opinions based upon his broad experience which, it is believed, were helpful to the Board. Dr. Violette has assisted in the preparation of elements of this submission. Information and documentation supporting EGDI's position provided by Dr. Violette are referenced in this submission. A copy of Dr. Violette's *Curriculum Vitae* is attached to his Affidavit, which is attached at Appendix "A".

6. EGDI also requested Ms. Judy Simon of IndEco Strategic Consulting Inc. to conduct an independent expert review of the Draft Guidelines based upon IndEco's extensive experience in both gas DSM and electricity Conservation and Demand Management ("CDM"). Many of IndEco's recommendations are referenced in this submission. A copy of the IndEco report, *Review of Draft DSM Guidelines for Natural Gas Distributors,* dated February 20, 2009, which includes

the *Curriculum Vitae* of its authors, are attached at Appendix "B". EGDI relies upon this report in support of its submissions.

7. Finally, EGDI attaches at Appendices "C" and "D" of this submission, a blacklined copy of the Draft Guidelines with changes proposed by EGDI and a clean version which EGDI respectfully requests should be adopted by the OEB for the reasons set out in this submission.

Specific Submissions

1. OVERVIEW

1.1 Background and
1.2 Overview of Draft Guidelines

Neither the Draft Guidelines nor the Paper specifically proposes a term for a multi-year plan or the process to select an appropriate term. EGDI submits that the natural gas utilities ("Utilities") should have the flexibility to propose a multi-year plan term of up to five years.

EGDI submits that a 5-year multi-year plan could appreciably increase the benefits of a multi-year plan approach, including providing additional certainty of funding to cost-effective programs and certainty to program participants that successful programs will continue. The concept of a 5-year term is not foreign to the OEB, with a recent example being the Board's approval of EGDI's 5-year Incentive Regulation Plan, 2008 – 2012 ("IR Plan") (EB-2007-0615).

Accordingly, it is submitted that where a Utility proposes a term of a multi-year plan of up to five years, there should be a presumption in favour of approval. This presumption should exist for the reasons set out above and because it has now been shown by the multi-year DSM Plan approved by the Generic Proceeding Decision, that a multi-year plan reduces the administrative burden to all stakeholders and reduces costs to ratepayers.

Another issue not addressed in either the Paper or the Draft Guidelines is the timing of applications to approve DSM multi-year plans. EGDI's current multi-year plan expires at the end of 2009. Given that EGDI's 5-year IR Plan expires at the end of 2012, the approval of EGDI's next multi-year plan will occur outside of a "full" rate case proceeding. It is the Company's view that there is no need for a multi-year DSM plan to be considered during a cost-of-service or rebasing application or during an annual rate adjustment proceeding during the term of an IR Plan.

EGDI believes that all parties and the OEB recognized the benefits of "de-linking" DSM proceedings from full rate cases with the approval of the Generic Proceeding. The Company is unaware of any complexity which has arisen or any difficulty negotiating or settling the terms of the current 5-year IR Plan by reason of the fact that a DSM multi-year plan had been approved in a different proceeding. By its decision dated February 11, 2008 in the IR Plan proceeding (EB-2007-0615), the Board approved the treatment of DSM program costs which were approved by the Board in EB-2006-0021 for the years 2007 through 2009 as Y factors.[2] There is, therefore, no apparent reason why the consideration of multi-year DSM plans need be heard together with a full rates proceeding.

There is also no apparent reason why the annual clearance of DSM variance accounts need be heard at the same time as other rates proceedings. Indeed, over the last several years, DSM variance accounts have been the subject of proceedings focused specifically on the clearance of amounts recorded in the several DSM variance accounts and in both instances, the proceedings were dealt with in writing and in an efficient fashion. EGDI submits there is no reason to complicate another rate proceeding by including DSM-related requests for approval. At a minimum, by de-linking DSM from other rates proceedings, parties interested in DSM issues will not have to spend time reviewing and

[2] EB-2007-0615, Decision, Schedule A, Settlement Agreement, N1T1S1 p. 17.

waiting for DSM issues to arise where unrelated issues are also under consideration. By spreading regulatory proceedings out over time, Utilities avoid the need to employ the resources that would be required to manage omnibus proceedings.

EGDI has included language at subsection 3.2 of the Revised Draft Guidelines consistent with the above.

2. COST EFFECTIVENESS

The Draft Guidelines reference, at footnote 1, "The California Public Utilities Commission (2001), Standard Practice Manual: Economic Analysis of DSM Programs and Projects". In fact, the best available information relating to the cost effectiveness (TRC) is included in the recently released document, "Understanding Cost Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy Makers", released by the National Action Plan for Energy Efficiency (2008). This reference has been substituted at footnote 1 in the revised Draft Guidelines.

2.1 TRC Calculation

It appears that the Draft Guidelines contemplate evaluating cost effectiveness on three separate occasions in respect of every program which a Utility contemplates implementing. The Draft Guidelines appear to require a determination of the cost effectiveness of a particular technology or measure. This evaluation is apparently required again once program costs have been determined. A third evaluation of cost effectiveness is then to be undertaken at the portfolio level. EGDI submits that this level of redundancy is not required.

While it may be possible to evaluate cost effectiveness at each of the three levels, it is submitted that it should only be undertaken as appropriate. As noted by IndEco in its attached report, Utilities already have an incentive to maximize

TRC benefits at the portfolio level to attain the best possible incentive. This acts as an encouragement to only include programs that have a benefit to cost ratio of greater than one, other than for “good reason”. Good reasons may include programs for low income groups or other hard to reach customer programs, and pilot programs. As a result, the Draft Guidelines should not include a requirement that every program meet or exceed a benefit to cost ratio of one or greater. This threshold should continue to apply at the portfolio level.

2.2 TRC Benefits

2.2.1 Avoided Costs Calculation

The Draft Guidelines contemplate essentially the methodology approved by the OEB in the Generic Proceeding. The Company has suggested several minor wording changes to provide additional clarity.

The Company does question whether the requirement to estimate natural gas avoided costs applicable to each customer class (page 10 of the Draft Guidelines) and the 4 steps enumerated are necessary and whether the Company’s current practice would thereby need to be changed. EGDI presently calculates the avoided costs for natural gas based upon 4 end uses of load shapes: space heating, water heating, combination space and water, and industrial processes. These end uses flow through the DSM portfolio TRC calculations and are allocated to the correct rate classes when accounts are cleared. It is the Company’s view that the change proposed in the Draft Guidelines is not practical and would add additional costs without any additional benefit. Accordingly, EGDI submits that its current methodology should continue.

EGDI notes Board Staff’s language at the bottom of page 9 of the Draft Guidelines which reads:

> "As avoided costs are long term projections, updating the costs, other than commodity costs, on a multi-year cycle should not cause benefits to be significantly under or over-stated."

EGDI submits that the same argument can be applied to many other inputs, including freeriders and spillover. Just as avoided gas costs are not expected to change significantly on an annual basis, the same is true for other TRC inputs. For example, prescriptive savings estimates should not change dramatically from one year to the next if based on the best available information when originally set.

Importantly, the Draft Guidelines appear to accept the importance of using the same avoided costs to calculate both any target and incentive amounts. Indeed, this is specifically what the Draft Guidelines propose in respect of avoided costs. However, for unexplained reasons, this same approach is not proposed in respect of updating input assumptions. While EGDI believes that the continued setting of targets is of no benefit (which is more fully discussed under Issue 3.5), in the event that the Guidelines approved by the Board continue to require the setting of targets, it is important that where avoided costs or input assumptions are updated and used for the calculation of the incentive amount, then they must also be applied to the target. To do otherwise would result in an unintended increase or decrease to the distributor incentive.

Where a program determined to be cost effective by the best available information at the time of its approval is subsequently argued to be no longer cost effective because of information published, perhaps in the year following the program's operation, the Utility is put at risk and this creates uncertainty. To not adjust a target to reflect the updated information would, in effect, penalize the Utility as a result of occurrences completely beyond its control.

Again as noted more fully later in this submission, EGDI believes that the preferred methodology is to retain the current approach, which is that input assumptions are applied only on a prospective basis, such that if an input or assumption is updated as part of the evaluation and audit process of 2009 results, that updated input or assumption only applies for the period of January 1, 2010 forward until changed again. This aligns with the current process

2.2.2 Natural Gas Savings

The Company proposes only several minor changes to the wording in the Draft Guidelines. In the first paragraph, it is believed that it should be recognized that TRC benefits are driven mainly by energy savings, which includes natural gas and electricity. While natural gas savings are indeed important, other energy savings are also important. The small change in the first sentence under this subsection captures this reality.

The Company is also suggesting adding the words "when practical" to the last sentence to make it consistent with other aspects of the Draft Guidelines which provide that the accounting for differences between the life of certain energy efficient equipment and the base case should be accounted for, but it is appropriate for the Utilities to weigh the costs of undertaking an additional analysis against the potential benefit.

2.3 Inputs and Assumptions

EGDI supports the process which is currently underway whereby Board Staff, with the help of a third party consultant, oversees the annual development of inputs and assumptions through a Board-mandated process. Currently, the Utilities and Intervenors are preparing their comments in respect of the draft report prepared for the OEB by Navigant Consulting Inc. entitled "Measures and Assumptions for Demand Site Managements" (the "Report"). Any comments in respect of the Report are due on March 6, 2009. It is believed that the Board's approval of new inputs and assumptions will follow a separate track from the Board's consideration and approval of the Draft Guidelines and the multi-year DSM plans that the Utilities will file in the spring.

EGDI supports this process and its continued use in the future.

2.4 TRC Costs

2.4.1 Equipment Costs

The Company has proposed a minor change to the last paragraph to accommodate cases where equipment requires less maintenance than its less energy efficient counterpart.

2.4.2 Program Costs

The Company has proposed some minor wording changes to subsection 2.4.2(iv) under the subheading "Monitoring and Evaluation Costs". While it may be desirable to attribute monitoring and evaluation costs to individual programs being evaluated, this is not always practical. In many instances, such costs cover numerous programs or technologies and are difficult to allocate specifically. The Company therefore submits that unless it is self-evident that certain monitoring and evaluation costs are attributable to specific programs, it is more appropriate to assign the balance of such costs to all programs. Given the percentage of costs which monitoring and evaluation costs make up, this should have very little impact on the cost effectiveness of any program.

2.5 Adjustment Factors

2.5.1 Free Riders

Under this subsection, the Company is similarly suggesting only several minor wording changes. Numerous programs are affected by free ridership estimates. Many of these programs are relatively small, and any change in freeridership will have a minimal impact on the program. It is therefore questionable whether free ridership estimates for all programs should be reviewed and updated on an annual basis, as appears to be suggested by the Draft Guidelines. In addition, it may not be appropriate where the size of the program, the expense to undertake a study, and/or the currency of the existing information on the subject does not justify undertaking an annual review. For these reasons, EGDI submits that free ridership estimates should be reviewed and updated over the course of a multi-year plan. The Draft Guidelines should not mandate an annual review and update in respect of every free ridership estimate.

Dr. Violette was asked to comment on the proposed requirement that free ridership estimates be updated annually. It is his experience that most utilities do not update freerider estimates annually. It is Dr. Violette's view that unless a program or a program's incentives change dramatically, there is no need to update freeridership annually. For large projects, freeridership may be best conducted on an ongoing basis to ensure that those responsible for making the project decisions are also available to help assess freeridership. These large projects may take a year or more to complete, so this is consistent with a multi-year assessment of freeridership. Accordingly, EGDI submits that the Draft Guidelines should not mandate an annual review.

2.5.2 Attribution

EGDI is supportive of the centrality principle continuing for use to determine attribution, as proposed by the Draft Guidelines. This principle has evolved over numerous proceedings, with good reason. Prohibitive and excessive rules relating to attribution would restrict partnerships that enhance conservation and the delivery of DSM. In the Board's Decision with Reasons in RP-2003-0203, paragraph 6.7.14, at page 61, the Board stated that it was "not concerned about the Company partnering with others to accomplish TRC savings, based upon the goal of achieving the greatest possible DSM benefits at the lowest cost, and in the simplest way possible."

The concept of attribution was again assessed by the Board in the Generic Proceeding where it ultimately approved the centrality principle, which provides that the Utilities would be entitled to 100% of the TRC benefits if a Utility can demonstrate that it has a central role in a program.[3]

2.5.3 Spillover

Given the evidence that confirms the existence and impact of spillover, the Company submits that it is appropriate to identify it as an adjustment factor in the TRC test. The Company submits that the evidentiary threshold which it must meet to receive approval to include spillover as part of the TRC Test is and should be no different than the evidentiary burden required to establish a free ridership estimate or, for that matter, any input and assumption. IndEco fully supports this view at section 2.3 of the attached report.

EGDI is concerned that some parties will argue that Board Staff's language in the second paragraph under this subsection increases the burden of evidence incumbent upon a Utility. EGDI has therefore suggested language which reflects this concern which is consistent with the treatment of other inputs and assumptions.

Dr. Violette was also asked to recommend a definition for "spillover" which, given his experience in other jurisdictions, would best serve natural gas DSM in Ontario. His recommended definition is:

> Spillover is comprised of energy savings that are due to the program but not counted in program records. Spillover is a combination of several factors that may influence non-reported actions to be taken at the project site itself (inside spillover), at other sites by the participating customer or Energy Efficiency Contractors (outside spillover), or by non-participants (non-participant spillover). For example, a participating customer or Energy Efficiency Contractor might observe the benefits of installing efficiency measures at a program site and, based on this experience, install the same or similar measures at other sites

[3] EB-2006-0021 Generic Proceeding Decision with Reasons, p. 42

without formally participating in the program. Spillover savings are added to the program's installed gross savings[4]

This definition has been included in the revised Draft Guidelines.

2.5.4 Persistence

As understood from the Draft Guidelines, persistence involves an estimate of both the retention (or removal) rate of equipment and technical degradation which is a separate issue in and of itself. In respect of the former, it is helpful to understand the difference between equipment life (the number of years installed equipment will operate until failure) and measure persistence (which attempt to take into account business turnover, early retirement of installed equipment and other reasons equipment might be removed or their use discontinued). EGDI currently accounts for removal rates in relevant programs and will consider an expansion of its assessment of equipment removal rates in its next DSM filing.

It should be noted that measure persistence often results from economic and business drivers, not necessarily the result of dissatisfaction with new equipment. These are factors which also would affect the base case. Furthermore, even when persistence is abbreviated due to economic factors, equipment is often sold and reused or recommissioned by a new plant owner or occupant. A prime example of this is food service equipment. The question which arises is whether Utilities should discount for reduced persistence and then attempt to measure re-use of such equipment? Ultimately, the costs of micro-analyzing program results must be weighed against the benefit of undertaking the analysis.

Technical degradation, however, is significantly more challenging, requiring research on a technology-by-technology basis. Measure life assumptions

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[4] This definition is used in evaluation efforts being undertaken by the New York State Energy Research and Development Authority (NYSERDA). See: "Commercial and Industrial Performance Program (CIPP) -- Market Characterization, Market Assessment and Causality Evaluation; Final Report." Prepared for the New York State Energy Research and Development Authority, by Summit Blue Consulting, LLC, Project Number 7721, May 2007.

previously approved by the Board are from published standards, such as ASHRAE, and provide a conservative estimate that is much less than the useful life of the equipment in many cases. This inherently accounts for marginal impacts that technical degradation would cause, since TRC calculations are already using values lower than the useful life of the equipment.

Plain and simply, in respect of calculating the impact of technical degradation, EGDI is unable to forecast what this will involve, the reliability of any estimates, nor the cost to undertake the research. According to Dr. Violette, the measuring of aspects of persistence can be very, very costly. California initially adopted very restrictive approaches to persistence that proved to be very expensive. Due to the expense, alternate and less prescriptive approaches to persistence were adopted. In some States, persistence has been addressed by simple periodic surveys to see if equipment is still installed and whether a plant or facility remains operational. Other jurisdictions have taken a decay rate formula approach rather than in-field verification of persistence.[5] Dr. Violette recommends that care be taken to develop practical approaches to assess persistence.

Ms. Simon of IndEco agrees with the above recommendation and notes (at page 6 of the IndEco report) that there is no corresponding requirement for the consideration of long term retention, technical degradation and persistence of savings in the Guidelines for Electricity Distributor Conservation and Demand Management (EB-2008-0037). Page 15 of the Electricity Guideline requires electricity distributors to account for the persistence of a CDM measure in accordance with the inputs and assumptions posted on the Board's Website. The Board's Inputs and Assumptions for Calculating Total Resource Cost Test, March 28, 2008, states that:

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[5] Focus on Energy Statewide Evaluation, Interim Benefit-Cost Analysis: FYO7 Evaluation Report, State of Wisconsin, Department of Administration, Division of Energy, February 26, 2007.

> "Distributors should assume 100% persistence in assessing CDM cost effectiveness unless otherwise updated by the Board. While persistence is not likely 100%, for practicality, it is necessary to make some simplifying assumptions." (Page 1)

EGDI therefore submits that the persistence requirements for gas Utilities should continue to be the status quo, which exceeds the standard required of the electric LDCs for CDM.

2.6 Fuel Switching

2.7 Pilot Programs

EGDI is of the view that the language in the Draft Guidelines is too limiting in that some parties may argue that it excludes pilot programs from being used to help design and test market transformation or low income programs. Pilot programs may be appropriate to test new delivery channels or marketing approaches to overcome barriers to market entry. Pilot programs should not be limited solely to the testing and evaluation of technologies new to Ontario.

Dr. Violette confirmed that in his experience, pilot programs are research and development projects designed to test specific hypotheses regarding a new energy efficiency program or a major change in current program design. This change might comprise a new delivery approach, test an organizational alliance, determine synergies in technology combinations, or assess the savings from a new technology based on an in-field pilot test. The common theme across all pilots is that uncertainty in a new aspect of program design or structure poses risks such that a small-scale pilot is warranted before engaging in full-scale roll-out of the new or modified program.

For the above reasons, the Company has included appropriate language expanding the definition of pilot programs under subsection 2.7 in the revised Draft Guidelines. It should be noted that Ms. Simon of IndEco similarly recommends that the definition of "pilot program" in the Draft Guidelines should be expanded as proposed by the Company.

3. BUDGETS AND METRICS

3.1 Budget Determination

The Company agrees that because each of the Utilities is accountable for money spent and the delivery of DSM programs, it is appropriate for budget levels to be proposed by the Utilities based on relevant factors and not be set by some monetary threshold which is unrelated to the Utilities' ability to deliver DSM on a cost-effective basis. EGDI believes that it will, for the foreseeable future, continue to be required to strike a balance between proposing a budget which responds to those that advocate the delivery of substantially more DSM programs and ratepayers concerned about the impact of such expanded programs on rates. It is appropriate for Utilities to be cognizant of both views and attempt to strike a reasoned balance in the budgets proposed.

3.2 Budget Term and Reporting

Uncertainty results from some of the language proposed in the Draft Guidelines under this subsection where it states: "The Term of the DSM budget will be the subject of a rate proceeding…." It is not clear whether Board Staff is proposing that a multi-year DSM plan filing be considered at the same time as an application for rebasing, or an annual rate adjustment proceeding. As noted at section 1 above, the Company is of the view that it is preferable to continue to decouple DSM proceedings from other rates proceedings. To make it clear that DSM applications need not be filed as part of other Company rates proceedings, EGDI is proposing that the Draft Guideline be amended as suggested in the revised Draft.

The last two paragraphs under this subsection in the Draft Guidelines relate to the DSMVA. The Company submits that some of the language under the last bullet should be removed from the Draft Guidelines for several reasons. First, it seems to imply that an application for recovery of amounts recorded in a DSMVA may only occur at the Utilities “next cost service application”. This is inconsistent with the Draft Guidelines elsewhere which provide that variance accounts will be cleared annually. Second, the language attempts to articulate the evidentiary burden incumbent upon the Utility. The language is not identical with wording in the Generic Proceeding Decision and is possibly inconsistent with the evaluation and audit provisions elsewhere in the Draft Guidelines. Amounts recorded in the DSMVA will be the subject of the evaluation and audit provisions of the Draft Guidelines and the subject of an application to the Board for clearance. There is, therefore, no need to include the language suggested at the last bullet.

The Company has also included some revised language dealing with the DSMVA. This language makes it clear that any additional spending must be used for incremental program expenses as approved in the Generic Proceeding Decision and as proposed by the Draft Guidelines. The Company does, however, suggest increasing the available limit to 20% above the annual DSM budget in place of the 15% maximum proposed in the Draft Guidelines. The Company submits that the goal of aggressively pursuing programs which prove to be very successful will be enhanced that much further by this increase.

3.3 Adjustments to an Approved Plan and
3.4 Targeted Program Spending

The Draft Guidelines propose a new provision which will require the Utilities to apply for Board approval where cumulative fund transfers among programs exceed 20% of the approved annual budget where it is proposed to reallocate funds to new programs that are not part of the distributors approved DSM plan. EGDI submits that this proposal is both unnecessary and, from a practical perspective, inappropriate for a number of compelling reasons. First, the need to obtain Board approval before allocating monies to an effective or promising program will act as a disincentive to the Utility and is counter-intuitive to the existence of the DSMVA which is intended to encourage a Utility to financially support successful programs. Second all parties to the Generic Proceeding agreed to the following at issue 3.3:

> **Program Design and Implementation**. The Utilities agree to the principle that their DSM program should be managed with regard to the best available information known to them from time to time. Normal commercial practice requires that a Company should react through changes to program design, implementation and/or mix, to material changes in base data as soon as is feasible given relevant operational considerations.

The Generic Proceeding Decision does not require the Utilities to first seek Board approval before making such changes.

On a related matter, dealing with targeted spending, at issue 1.7, the Board accepted the following rule:

> To the extent that actual sector level spending then varies significantly from the ratios identified in the plan, parties may challenge the appropriateness of the deviation from the plan when the Utility seeks approval for the clearance of relevant accounts and the Board can make such order as is appropriate.

Again, there is no requirement to seek approval for significant sector level spending variation. Interestingly, this very language is proposed at subsection 3.4 of the Draft Guidelines (which EGDI supports). This appears to be inconsistent with what is proposed at subsection 3.3.

Issue 1.5 at the Generic Proceeding asked what process and rules should be available to amend a DSM plan. The Board accepted demonstration of "undue harm" as the threshold which must be met on an amendment application. The Board accepted the position of the Utilities that the Board should amend the multi-year plan during the currency of that plan only in exceptional circumstances.

The proposed 20% threshold is inconsistent with each of the above rules which, EGDI submits have worked well. In addition, it is important to note that while a DSM plan is made up of many programs and associated budgets, EGDI has always understood that the Board was not approving each program budget specifically but rather the portfolio of programs, leaving it to the Utility to support programs more or less depending upon their success and other market factors.

Dr. Violette is of the view that the proposed 20% rule would operate as a disservice to the efficient delivery of cost-effective DSM due to the time that would be required to prepare an application and to allow a Board proceeding to run its course, even if in writing. Dr. Violette notes that distributors work in dynamic markets that often have highly seasonal uptakes of equipment. The efficiency of DSM activities could be reduced if Board approval results in delays.

IndEco points out, under Section 2.6 of its attached report, that while electric utilities have been required to apply for approval where cumulative fund transfers exceed 20%, the requirement has not been imposed on gas Utilities for good reason. Specifically, IndEco notes:

> "Unlike for CDM, this requirement was never imposed for gas DSM. This budget flexibility restriction was not found to be necessary at the inception of gas DSM with E.B.O. 169-III, or in the Generic Decision. With more than ten years of experience in gas DSM (and Enbridge since 1995), the gas distributors have proven themselves to be responsible in re-allocating dollars in their DSM budgets to maximize savings/TRC. As a result, other than harmonization with current practice on the electricity side, which in this case would place an unnecessary restriction on gas DSM, there is no reason to impose this new requirement on the gas distributors."

Finally, the requirement that portfolios be cost effective is a further reason why a 20% adjustment threshold is not necessary. The cost effectiveness requirement ensures there will be net benefits to ratepayers even where there is a change in funding levels to some programs or sectors.

Accordingly, EGDI submits that subsections 3.3 should be amended to include language which is consistent with the above. The proposed 20% approval threshold should be removed from subsection 3.3. The Company supports the proposed language at subsection 3.4.

3.5 TRC Savings Metrics

The Company submits that the time has come to acknowledge the "myth" of TRC savings targets having any beneficial impact on the design and delivery of cost effective DSM. TRC savings targets may have served their purpose when natural gas DSM was in its infancy but with the Utilities being well into their second decade of DSM activities, savings targets are no longer required.

Indeed, as shown by the growth and increasing sophistication of many electric distribution companies in their delivery of CDM where no TRC savings targets exists, the savings target is not a prerequisite to undertaking cost effective DSM. Electric LDC's have from the outset operated on the basis of a percentage of net TRC SSM without a savings target. Accordingly, there is no intuitive or compelling reason why natural gas Utilities, who have even greater experience, should be treated differently and required to undertake the labour intensive and highly contentious exercise of negotiating TRC savings targets.

Significant time and ratepayer funds have been spent in previous DSM proceedings to debate the concepts of targets, which is generally understood to be an imprecise exercise. It is believed that all parties share the view that targets are imprecise and subject to "gaming". In 2004 and 2005, EGDI produced over $320 million of net benefits, or over $10 in benefits for every dollar spent; yet EGDI did not receive a single dollar of incentive for this business activity due to "gaming" of targets.

The fact is that DSM program managers are incented by the expectation of earning SSM, not by a threshold target. The driver for DSM managers and their staff is not linked to the formulaic SSM targets approved by the Board in the past. Performance is judged by the employee's results delivering cost effective DSM programs which optimize net TRC benefits.

It is a fact that the selection of a TRC savings target has had little to do with any science or empirical data. It has been largely linked to the negotiations between the Utilities and intervenors and is more a function of the trade-offs and compromise that are the hallmark of settlement negotiations. The Company does not believe that any credible party will argue that TRC savings targets truly act as an incentive for a natural gas Utility to undertake and deliver cost effective DSM. It is time for this relic of the 1990's to be laid to rest.

Another relevant fact is that TRC target setting for multi-year plans becomes all the more difficult and complex as the length of the plan increases. All parties accept that it is impossible to develop a formula which will fairly set future TRC savings targets that will adjust automatically for all future potentialities including changes in the economy, the entry of new market players and market trends. This is particularly relevant in the context of the current economic recession. Acknowledging this, one should question the benefit of creating target setting methodologies in the first place.

Dr. Violette also questions the benefit of the continued use of targets, particularly given the fact that the vast majority of the benefits of undertaking DSM already flow to ratepayers. Given that an SSM, even in the most successful of years, will only represent a small percentage of the net TRC generated, Dr. Violette questions the efficacy of Parties, Board Staff, and the Board expending time negotiating or attempting to demonstrate the appropriateness of one target setting formula versus another.

According to Dr. Violette, when evaluating any changes in targets or incentive mechanisms, it is important to look at the larger picture in addition to examining the micro assumptions that comprise specific calculations. Under a scenario where EGDI earns an SSM equal to 5% of net TRC generated, ratepayers still realize 95% of the net benefits. This sharing arrangement inherently provides considerable protection to rate payers so the cost of adjustments made at a micro level to the input assumptions results in unnecessary costs and complexities.

To help understand this point, Dr. Violette offers the following example where the TRC Target is 100 units of net benefits and the utility receives as an incentive equal to the value of 5 TRC net benefit units. Now, assume that benefits are over-estimated by 20% for some reason, i.e., the estimated TRC net benefits are biased and estimated to be 120 TRC net benefit units when the true amount (is 100 TRC units). The result would be that the utility would receive the value of 6 TRC units, or 6% of the true value of 100 TRC units. As a result, an error in the portfolio estimate of TRC net benefits of 20% (larger than can be expected by any single adjustment in a technology or program input parameter) changes the share of benefits between the utility and ratepayer by only 1%. The balance of shared incentives that are so heavily weighted towards ratepayers mitigates the effect of any likely update in DSM program inputs on the shared savings. As shown above, an error in the target due to any bias (e.g., input variables) of 20% would only have a 1% impact on the sharing of benefits between ratepayers and the utility. Stepping back and looking at the overall context of the Target setting mechanism shows that little is gained by micro adjustments to any Target. Given this, simplicity most appropriately incents the utility to engage in aggressive energy efficiency activities and benefits all parties.

Some stakeholders want to increase the funds spent on energy efficiency taking levels into areas of uncharted territory. This will magnify the problems inherent in the use of targets. It is inconsistent to place such a high importance on achieving aggressive conservation without clear incentives for the utility. Paradoxically, a calculation methodology that is overly complex produces limited gains in accuracy. To achieve aggressive conservation goals, metrics should be transparent (not moving) and processes straightforward.

The Company submits that the use of targets is not in alignment with the Province's goal to aggressively pursue conservation. If TRC savings targets remain a requirement, a substantial amount of time will be expended during the review of the Company's next multi-year DSM plan attempting to devise a formula for future target setting. In the event that the Utilities and Intervenors cannot reach agreement, then an oral proceeding will be required that will focus EGDI, intervenor and Board resources on debate about theory, rather than allocating these resources to achieve conservation results.

The removal of the need to set targets should not be confused with a Utility providing a forecast in its multi-year plan filing of the benefits it hopes to generate and the incentive calculation that would accompany these results. It is entirely appropriate that intervenors and the Board understand what will be the result if the Utility's forecasts are met. However, a forecast should remain precisely that, a forecast, and should not be used to unnecessarily complicate an SSM calculation by making it a "target".

Some intervenors in the past have argued that TRC targets are necessary to promote "excellence" by a utility. Dr. Violette is of the view that such a submission is without merit. In his view, achieving positive net benefits requires the delivery of a sophisticated DSM program and a substantive effort by the Utility. Dr. Violette confirms that it is not easy to deliver DSM programs, which is a common mistake that has been built up by many supporters of DSM, i.e., that energy efficiency is like "picking low hanging fruit". In Dr. Violette's view, this does a disservice to the professionals in the energy efficiency field. Building a set of DSM activities is better viewed as building a DSM power plant or, in the case of natural gas, building the delivery system. It is an increasingly complex undertaking.

Dr. Violette notes that the delivery of DSM programs is challenging, takes resources and time. To be successful, the Utility needs to develop:

(i) Program concepts;

(ii) Value propositions and customer assessments;

(iii) Marketing;

(iv) The ability to "make the sale" (getting the signature and approval of a participant – sales are different from marketing);

(v) Delivery channels – getting appropriate industry infrastructure;

(vi) Fulfillment (getting the service or technology to the customer and installed properly);

(vii) Quality control (important throughout the program, and many quality control management systems are typically part of program design and tracking);

(viii) Financial accounting; and

(ix) Stakeholder management.

It is Dr. Violette's view that the above steps represent a significant business effort, akin to the development and roll out of a new product or service, with the same set of challenges. Not all programs will be successful. Many will need a "shake out" before they become successful. Accordingly, Dr. Violette is of the view that where a utility has undertaken the steps necessary to take a program to a point where it delivers TRC net benefits, this is an accomplishment, and the utility's rewards should begin at that point.

Accordingly, the Company submits that the Draft Guidelines should read: "TRC savings targets are not required in respect of resource acquisition programs."

3.6 Market Transformation Metrics

The Company continues to agree as did parties to the Generic Proceeding that market transformation programs are not amenable to a formulaic evaluation approach and therefore should be assessed on an individual basis using metrics which are suitable to a given program. In many instances, this will require setting goals or objectives (i.e., metrics) which must be reached to be eligible for a shareholder financial incentive. However, there may be instances where another type of metric other than a specific "target" is appropriate. Accordingly, the Company proposes modest changes to the wording which it believes helps make it clear that targets are not mandatory in all cases, although each utility would continue to forecast its results in a multi-year filing.

3.7 Low Income Metrics

For the reasons set out under subsection 3.6 above, the Company proposes a similar change in wording under this subsection.

It also notes that this is one subsection which may be impacted by the Board's decision following the Low Income Consultation which occurred in 2008.

4. LRAM

4.1 Eligible Programs

The LRAM may be subject to the adjustment factors identified under subsection 2.5, including freeriders and spillover. The rules in respect of any attribution factor adjustment are set out at subsection 2.5.2. There is, therefore, no need to include the last sentence under subsection 4.1.

4.2 Calculation of LRAM

The concept and application of LRAM has been tested over time by the Board. The general concept is captured in the Draft Guidelines, but is lacking in the rules needed for a distributor to apply the concept. Revisions have been made based on past Board decisions in the attached revised Draft Guidelines under this subsection.

It is the Company's view that the Draft Guidelines include language which is repetitive of other sections and therefore redundant. It is submitted that this is true of all of the second and third paragraphs under subsection 4.2. The Company specifically notes that the last sentence of paragraph 3 is inappropriate in that it appears to set an evidentiary standard or burden of proof for spillover effects.

One further note relates to the requirement that the assumptions used for the LRAM be the best available at the time of an audit. While the Company accepts this as appropriate for LRAM, it submits that it is important to fix a date after which no further information and documentation can be used to influence a change in the LRAM. For example, where a party believes that a study or paper that may have an impact on an input or assumptions is "pending", it is the Company's experience that the Company and/or the auditors may be asked to delay their work in the hope that the further study or paper will be produced and used for the purposes of the audit. To avoid this, the Company has proposed language under section 6.3 setting a deadline for the submission by any party of any study or paper for use in the evaluation and audit process.

4.3 LRAM Variance Account

EGDI supports the continuation of this account.

4.4 Timing of LRAM Application

The Company submits that the second sentence in the Draft Guidelines under this subsection does not relate to "timing", is repetitious of language elsewhere, and should be removed.

5. INCENTIVE PAYMENT MECHANISM

5.1 Eligible Programs

The Company does not propose any changes to the language of the Draft Guidelines.

5.1.1 SSM for Resource Acquisition Programs

The Draft Guideline appears to mandate the continuation of a non-linear approach to the development of a shared savings mechanism. This is simply an extension of past practices and, as noted at subsection 3.5 above which deals with TRC savings targets, EGDI, IndEco and Dr. Violette each independently reached the same view that there is no reason for its continuance. The fact is that a dollar worth of TRC benefits has the same value to ratepayers regardless of whether it is the first or the last dollar generated by the Utility in a given year. Again, Utilities are motivated by the SSM, not an artificial TRC savings target.

As noted in the attached IndEco report, there is no government policy in place that indicates that gas TRC is less valuable to society than electricity TRC. In the case of both CDM and DSM, it is clear that the subject distributor is delivering a service, every unit of which is equally beneficial to society. Each distributor should therefore be awarded equally for each TRC unit achieved.

Accordingly, the Company submits that the Draft Guidelines should not mandate that the reward structure continue to be a non-linear function relative to TRC savings. EGDI submits that distributors should be approved to use a linear or other mechanism for consideration by the Board. Given that this is the way that Electric LDC's have been operating in Ontario for a number of years, the Company fails to understand the need to prohibit a natural gas Utility from applying this transparent and straightforward structure for its SSM. Both Ms. Simon of IndEco and Dr. Violette agree that removing the target requirement will streamline the regulatory process.

The Company also submits that if inputs and assumptions are to be updated for the purposes of calculating the SSM (something which EGDI does not support), consistent with its comments in respect of the LRAM, then there should be a deadline for the submission of any relevant paper or study for the purposes of updating relevant inputs and assumptions.

In the event that the Board does not accept EGDI's position and approves guidelines which retain a TRC savings target, as noted earlier, the Company submits that for the purposes of determining whether the Company has met its TRC target, it will be necessary to adjust the target to reflect any update in inputs and assumptions that will also be used for the purposes of calculating the TRCs generated.

At page 26 of the Draft Guidelines, Board Staff include the following sentence:

> "The utilities have had several years of experience to conduct evaluation studies and make major changes to the input assumptions and as a result there is no need to lock in the input assumptions from the year before."

As noted by Ms. Simon in the attached IndEco report, at page 11, this is not a DSM maturity issue. The removal of the requirement to lock in input assumptions for the calculation of SSM would act as a limitation on program delivery that would occur regardless of the maturity of the distributor. The proposed framework change would remove the very certainty needed for a distributor to make DSM investment decisions.

The Company submits that one of the reasons why the Generic Proceeding Decision and all previous gas DSM decisions did not require inputs and assumptions updated for the purposes of the SSM calculation was the recognition by parties that it would not provide a fair incentive to Utilities acting in good faith based on a Board-approved DSM plan. The requisite adjustments to targets, of course, adds additional complexity, effort and cost and, in EGDI's view, would likely only result in minimal changes to the total SSM claim. Accordingly, all parties agreed at issue 3.3 during the Generic Proceeding that changes to inputs and assumptions during the audit of the previous year's results would not affect the previous year's SSM claim but would operate for the purposes of the SSM claim in the year of the audit forward. Specifically, the Settlement Agreement accepted by the Board states by way of example at page 11 of the Generic Proceeding Decision:

> If in June 2008 the audit of the 2007 programs demonstrates a change in assumptions, that change shall apply for SSM purposes from the beginning of 2008 onwards until changed again.

The Company submits that by eliminating TRC savings targets and a non-linear SSM mechanism, the calculation of SSM claims will become more transparent and simplified. The Company has therefore proposed changes to the wording under subsection 5.1.1 of the Draft Guidelines to reflect these views.

5.1.2 Market Transformation Incentive and 5.1.3 Low Income Program Incentive

The Company has suggested two wording changes to these subsections which are consistent with its view that the metrics that are ultimately proposed for market transformation and low income programs may not necessarily include a target.

5.2 SSM Variance Account

The Company agrees this Account should continue.

5.3 Timing of Application

The only language required under this subsection should relate to the timing of applications for clearance. The balance of the language in the Draft Guidelines is repetitious of other subsections and should be removed.

6. PROGRAM EVALUATION AND AUDIT

6.1 Evaluation Plan

EGDI proposes a wording change to the first bullet under this subsection, replacing the word “measuring” with the word “assessing”, which is a more apt description of what is contemplated. The term “measuring” connotes a formulistic mathematical model over and above the methodologies used to determine cost effectiveness, LRAM and SSM. A less formulistic, observational assessment of a program’s effects may be appropriate, and such an approach should not be subject of debate about whether the assessment methodology is sufficiently mathematically precise. By using the term “assessing”, Utilities will have the flexibility to propose methodologies which are appropriate and suitable for programs. It should be noted that the term “assessing” is included in the second bullet of the Draft Guidelines under this subsection, which EGDI believes is appropriate.

6.2 Program Type Specific Guidelines

6.2.1 Direct Acquisition Programs

6.2.2 Market Support Programs

EGDI does not propose any change to the language under these subsections.

6.2.3 Custom Projects

The Draft Guidelines appear to make it a requirement in respect of each selected custom project according to the evaluation plan that the Utilities undertake a professional engineering assessment of the savings generated. It is unclear whether this requirement mandates the retention of a licensed professional engineer, who would then stamp the savings calculations, or whether natural gas Utilities will be entitled to rely upon published studies and information about similar custom projects elsewhere and/or their own internal professional training and experience. Industry experts and business partners are technically trained to assess energy projects, but certainly not all are professional engineers.

It should be noted that a professional engineer has not been required or involved in the majority of custom projects which EGDI has undertaken in the past. Although individual projects do not require a professional engineer, custom project evaluation and independent audit activities often include an engineer, where applicable. Mandating that only engineers can conduct custom projects appears contrary to Ontario's initiative to create green jobs since it will serve as a barrier to qualified employees that are not licensed engineers.

EGDI submits that so long as persons appropriately experienced and trained provide a professional assessment, then the purpose of undertaking an evaluation will have been met. EGDI therefore suggests that the words "each custom project will incorporate a professional engineering assessment of the savings" be changed to "custom projects will incorporate a professional project specific assessment of the savings". Wording has been revised in the first paragraph of the revised Draft Guidelines to reflect this.

Another issue which arises with the proposed language in the Draft Guidelines is the use of the words "each custom project" in the second paragraph under the subsection. This language appears inconsistent with the third paragraph which confirms that Utilities will continue, as is presently the case, to conduct on a random basis samples of custom projects as part of the evaluation process. To make it clear that the evaluation process will continue to involve a sampling of custom projects, language has been added to the first sentence of the third paragraph under this subsection confirming that:

> "A special assessment program should be implemented for the evaluation of custom projects."

Uncertainty also exists in relation to the words "assumptions with respect to measure life should reflect <u>actual</u> expected measure life" in the last sentence of paragraph 2. Previous DSM decisions of the Board have followed the precedent of using Board-approved measure lives. Is the proposed language intended to include elements of technical degradation which, as noted earlier at subsection 2.5.4, requires further research and consideration? EGDI therefore suggests removing the word "actual" from the above language.

6.2.4 Market Transformation Programs

6.2.5 Low Income Customer Programs

No changes are proposed to these subsections.

6.3 Implementation of Updated Input Assumptions

EGDI agrees that, as proposed in the Draft Guidelines, in considering the prudence of any spending in excess of an approved budget that has been tracked in the DSMVA, the input assumptions available to the Utilities at the time a program is implemented shall be considered. However, as noted earlier, EGDI does not agree that input assumptions should be revised such that its performance for SSM purposes is based upon revised input assumptions as opposed to those used from the beginning of a year under review. As noted by Ms. Simon in the attached IndEco report, the removal of the requirement to lock in input assumptions for the calculation of the SSM places undue risk on distributors. As noted in the IndEco report, while it is true that risks may be less for a program that has been delivered for many years, for new programs or where conditions change, there still may be situations for which the distributor cannot adapt. Accordingly, IndEco agrees that gas distributors should not be penalized for changing conditions they cannot control.

EGDI proposes that the methodology all Parties agreed to as part of the Generic Proceeding Decision continue (which is consistent with the requirements for electricity distributors). EGDI submits that the same language dealing with the SSM from the Generic Proceeding Decision be included in the Draft Guidelines, specifically:

> "**SSM** assumptions used from the beginning of any year will be those assumptions in existence in the immediately prior year, adjusted for any changes in the audit of that prior year. By way of example, if in June of 2008 the audit of the 2007 programs demonstrates a change in assumptions, that change shall apply for SSM purposes from the beginning of 2008 onwards until changed again."[6]

As a result of the above change, it is necessary to amend the Draft Guidelines as it relates to the LRAM to remove references to the SSM and other financial incentives. The revised Draft Guidelines provides that, in the case of the LRAM, input assumptions used should be the best available at the commencement of the independent third party review.

This being stated, Dr. Violette has found that the "best information" at any point in time can be problematic. There are primary, secondary, infield, judgmental and referential studies that produce alternative input assumptions from across North America. Dr. Violette does note that, in Ontario, great care has been taken to use input assumptions reasonable for the province and the specific programs in the DSM plan. Given this, Dr. Violette believes that it is appropriate to set a "deadline" for the consideration of any new information lest the pending

[6] Decision with Reasons, EB-2006-0021, dated August 25, 2006, p. 11 of 63.

availability of new information be the catalyst for delay completing the evaluation, audit and clearance of the previous year's results. By setting a deadline, it will also reduce uncertainty associated with undertaking DSM plans in a current year based upon input assumptions that could change as a result of the evaluation and audit process. Accordingly, EGDI submits that input assumptions should only be updated for the purposes of the previous year's LRAM where the new information has been provided to the applicable natural gas Utility up to the commencement of the audit. Updates developed in a program year should be included in the annual Input Assumptions update process and applied to the next program year.

6.4 Evaluation Report

The only revision that the Company proposes in respect of this subsection is to number each of the four subheadings under this subsection.

6.5 Independent Third Party Review

The Draft Guidelines have been revised to note that the Utilities are required by Section 2.1.12 of the Natural Gas Reporting and Recordkeeping Requirements (RRR) Rule for Gas Utilities already includes timing requirements for the annual audited DSM results. This section of the Draft Guidelines has been amended to reflect these requirements.

7. DSM CONSULTATIVE

EGDI consults with all stakeholders that can add value to its DSM portfolio. EGDI has held consultative meetings to facilitate this goal. This being said, only the Utilities are accountable for their DSM activities, and it is imperative, as the Draft Guidelines confirm, that the role of stakeholders, either through the DSM or its EAC, be advisory in nature. EGDI therefore supports the Draft Guidelines in this respect. The Company has made several minor wording changes under this subsection to provide additional clarity.

8. ACCOUNTING TREATMENT

8.1 Funding of DSM Programs and
8.2 Cost Allocation

It is important to note that the vast majority of DSM programs undertaken by the natural gas Utilities have been both funded by ratepayers and undertaken for the benefit of ratepayers. Only a tiny percentage of programs have received funding from third party entities such as the OPA. Given this and the fact that gas ratepayers have been almost exclusively the beneficiaries of the DSM programs undertaken by the natural gas utilities, DSM budgets have been developed, like other departmental budgets, for the purposes of determining the Utility's revenue requirement. EGDI sees no reason why this process should change and the DSM budget be subject to a different cost allocation treatment. The fact is that a significant portion of many, what would be described as "overheads", cannot be attributed solely to DSM activities. The cost to operate and maintain the Company's head office is the same with or without the DSM activities which are undertaken for the benefit of ratepayers. These costs should properly remain part of the Utility's distribution revenue requirement. To do otherwise would simply result in increased complexity and costs without additional ratepayer benefit.

EGDI understands that where it receives funding for DSM from third parties for certain programs, the costs of these programs should be handled on a fully allocated basis. However, where funding is from ratepayers, there is no cohesive reason to depart from the present practice of using marginal costing to determine the cost effectiveness of DSM programs. In addition to the added complexity and costs associated with calculating ratepayer-funded DSM activities on a fully allocated basis, EGDI is of the view that the additional costs would be nominal and would have little or no impact on cost effectiveness. The Company believes that the exercise is simply not warranted. Accordingly, the revised Draft Guidelines have been amended to reflect this position under subsection 8.2.

In the unlikely event that a Utility obtains third party funding and this is available to replace funding currently coming from ratepayers, EGDI, IndEco, and Dr. Violette all agree that it should not be necessary for a natural gas utility to expend the time and effort to apply to the Board for approval to direct the freed up funds to existing or new programs. For the same reason that the Generic Proceeding Decision did not require natural gas Utilities to seek Board approval in respect of changes in program funding levels in response to market changes and other operational considerations, EGDI sees no benefit to mandating yet a further approval process (whether 20% or otherwise) at this time. An additional approval process will only detract from the Utility's primary objective, namely, the delivery of DSM. EGDI has therefore removed the last sentence in the revised Draft Guidelines under subsection 8.1.

8.3 Revenue Allocation

The Company submits that additional language should be included in subsection 8.3 to confirm that revenues earned from contracts with third parties, such as the OPA, be kept separate from the Utility's Distribution Revenue Requirement. Language to this effect has been included under subsection 8.3 of the revised Draft Guidelines.

8.4 DSMVA

EGDI is uncertain as to whether or not the Draft Guidelines provide for the status quo or add an additional requirement to any recovery. The Draft Guidelines state that recovery will be permitted provided the distributor "…has achieved its annual TRC savings or other targets…"

Issues 6.1, 6.2 and 6.3 of the Generic Proceeding dealt with the DSMVA. In the Generic Proceeding Decision, the Board approved the DSMVA with the following characteristics:

> "Parties agree that the DSMVA shall be continued. The DSMVA shall be used to "true-up" the variance between the spending estimate built into rates for the year and the actual spending in that year. If spending is less than what was built into rates, ratepayers shall be reimbursed. If more is spent than was built into rates, the utility shall be reimbursed up to a maximum of 15% of its DSM budget for the year. All additional funding must be utilized on incremental program expenses only (i.e. cannot be used for additional utility overheads). For greater certainty, program expenses include market transformation programs. "

The Board, at page 30 of the Generic Proceeding Decision, found the above wording to be "reasonable" and stated:

> "The DSMVA will allow utilities to aggressively pursue programs which prove to be very successful, even where this causes them to exceed the Board approved budget (by up to 15%)."

The Draft Guidelines appear to be in conflict with the language of the Generic Proceeding Decision as it appears that the Utility would be at risk of not recovering any overspending, even though the overspending was entirely on incremental program expenses (i.e., not the Utility's overheads) that benefit ratepayers. The recovery of monies spent to continue successful programs, particularly where such monies are spent entirely on incremental program expenses, should not be dependent upon exceeding some preset target or threshold, which appears to be a throw back to DSMVA methodologies of many years ago.

If recovery is dependent upon a target or threshold level being exceeded, natural gas utilities will be disinclined to aggressively pursue programs until there is absolute certainty that the target or threshold has been exceeded. This will only lead to uncertainty and delay in programs which could be successful if continued. There is no apparent valid reason why such a requirement should exist, especially for Utilities with a proven track record. It is not just the many months it would take to make an application and receive a decision, but the collateral impacts to customers caused by destroying program momentum and resulting negative impact on program results.

Finally, the Company submits that the goal of aggressively pursuing programs which prove to be very successful will be enhanced if the maximum exceedance from the DSM budget is increased to 20%. This will give the Company the additional flexibility of pursuing maximum benefits for its ratepayers.

Amendments to the Draft Guidelines to reflect the above are found in the attached revised Draft Guidelines.

8.5 CO2 Offset Credits Deferral Account

The CDOCDA was introduced by the OEB in the Generic Hearing and was developed to record amounts which represent proceeds resulting from the sale of or other dealings in earned carbon dioxide offset credits. There have not been any entries in this account since its inception. Now is the time to provide an incentive to distributors to create business opportunities to help customers manage carbon dioxide emissions.

Based on the right business incentives, distributors may have the ability to develop business offerings to work with customers to manage emission commitments. The CDOCDA is to be removed in order to provide distributors an opportunity to make this a profitable part of their business. This is consistent with the incentive regulation principle of minimizing deferral accounts. Through the current incentive regulation earning sharing mechanism, there is an inherent opportunity for ratepayers to benefits from this business opportunity should it become successful.

8.6 Recording of DSM Spending Not Funded Through Distribution Rates

No changes.

9. ANNUAL REPORTING GUIDELINES

EGDI assumes that the proposed Annual Report is in addition to the Evaluation Report required under subsection 6.4 of the Draft Guidelines. Presumably, to the extent that the Evaluation Report addresses the information required under Section 9, it will not be necessary to repeat the same information. Traditionally, the Annual Report includes discussion on evaluation activities undertaken and forms the basis for the audit of the DSM portfolio. Having these elements in separate documents seems disjointed and will make it more difficult for an auditor.

10. ADMINISTRATION FILING GUIDELINES (NEW)

EGDI recognizes IndEco's recommendation in respect of section 10 based on their independent review. The process would be much more streamlined if IndEco's recommendation in respect of section 10 is accepted and this section in its entirety is removed from the Draft Guidelines. In the event that the Board does not decide to accept this recommendation, EGDI makes the following comments below.

10.1.1 Program Funding Through Distribution Rates

EGDI notes at Item 3 that there is reference in both the second and third bullets to DSM rate riders which, of course, do not exist for natural gas DSM purposes. If, as IndEco recommends, the entirety of Section 10 is not removed, it appears that it requires further revisions.

EGDI is proposing only minor changes to the information required under Item 5 to make it consistent with earlier changes to the subsection dealing with pilot programs. As noted earlier, EGDI believes that pilot programs should not be limited to only those apparently eligible under the Draft Guidelines. Consistent with this, some minor wording changes at Item 5 are required.

10.1.2 LRAM

10.1.3 SSM

10.1.4 Adjustments to an Approved Plan

EGDI proposes that this subsection include language which mirrors the Generic Proceeding Decision which approved "undue harm" as the appropriate threshold for applications to amend a multi-year DSM plan. Specifically, EGDI proposes the following language:

> "An application for adjustments to an approved multi-year DSM plan should occur only in exceptional circumstances. Any application for an amendment must meet a very high onus to demonstrate undue harm absent the application. Where such an application is made, it should include evidence to demonstrate the likelihood of undue harm in the absence of the application being made and any other supporting evidence."

All of which is respectfully submitted.

Dated: February 20, 2009

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Enbridge Gas Distribution Inc.,

by its Counsel, Dennis M. O'Leary

EB-2008-0346

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF a Consultation on the Development of Guidelines for Demand Side Management to be used by Natural Gas Distributors

AFFIDAVIT

I, DANIEL M. VIOLETTE, of Boulder, Colorado, United States of America, solemnly declare as follows:

1. I appeared and was qualified as an expert witness at the Ontario Energy Board's DSM Natural Gas Generic Proceeding (EB-2006-0021). As a result, I have a good deal of familiarity with the delivery of natural gas DSM by Enbridge Gas Distribution Inc. ("EGDI") and the Ontario DSM regulatory regime. I am also very familiar with the regulatory regime in numerous other jurisdictions in Canada and the United States. My *Curriculum Vitae* is attached hereto and marked as Appendix "A".

2. I have been asked by EGDI to review the Board Staff Discussion Paper: Draft Demand Side Management Guidelines for Natural Gas Distributors, dated January 26, 2009, and Appendix "A" thereto, being the Draft DSM Guidelines, for my comments and any views as to how the Guidelines could be improved. I have provided my comments to EGDI, who has incorporated them into its Submission to be filed February 20, 2009 in this proceeding.

3. I have reviewed EGDI's Submission and confirm that the comments attributed to me are accurate and reflect my professional opinion.

Declared before me at Boulder, Colorado, this 19th day of February, 2009.)	Daniel M. Violette **DANIEL M. VIOLETTE**

Julene Gonzales
Notary Public

JULENE GONZALES
NOTARY PUBLIC
STATE OF COLORADO
My Commission Expires 01-11-2010

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DANIEL M. VIOLETTE

EMPLOYMENT HISTORY

- Principal and Founder, Summit Blue Consulting, Boulder, CO, 2000-present
- Sr. Vice President, Economics and Analytics, Hagler Bailly Consulting, Inc., Boulder, CO, 1996-2000
- Sr. Vice President,/EDS Management Consultants, Boulder, CO, 1994-1996
- Sr. Vice President, XENERGY Inc., Boulder, CO, 1992-1994
- Sr. Vice President, RCG/Hagler Bailly, Inc., Boulder, CO, 1987-1991
- Cofounder and Sr. Vice President, Energy and Resource Consultants, Inc., Boulder, CO, 1979-1987
- Economist, Energy and Environmental Analysis, Inc., Boulder, CO, 1977-1979

PROFESSIONAL EXPERIENCE

Dr. Violette is a leading authority on the application of quantitative methods to supply-side and demand-side resource planning for electric and gas utilities. He has authored guidebooks on the application of these methods, and he has presented testimony and participated in litigation support efforts addressing new generation, demand-side actions, and load management / demand response technologies. He has performed assignments for over 50 utilities and energy companies in North America and has testified before regulatory authorities in over a dozen states. His work has been documented in handbooks authored for the Electric Power Research Institute, International Energy Agency, OECD, and the American Gas Association.

In his 20 years of consulting experience, Dr. Violette has conducted assignments for clients across North America and internationally. This work includes over 500 evaluations of energy efficiency program portfolios, innovative pricing programs, and demand response initiatives. He has also worked on new energy services products focused on information and demand-side technologies for leading technology companies.

His consulting engagements have ranged from focused quick-hit white paper studies to managing multi-year, multi-million dollar assignments. For electric and gas utilities, he has conducted assignments in the areas of resource planning, DSM planning/operations and evaluation, risk assessment, rate design, new energy services analyses, and organizational studies. He has provided support to utilities in merger and acquisition analyses, rate cases, and regulatory hearings, as well as in securities and environmental litigation.

He has conducted on-site workshops at nearly a dozen client sites and numerous workshops on planning, DSM and evaluation for EPRI, as well as training courses for the Association of Energy Services Professionals and the Peak Load Management Alliance. He was selected to teach the workshop on Necessary Statistics and Data Analysis for the evaluation of energy programs (DSM and pricing) at the International Energy Program Evaluation Conference (IEPEC) for each of the three past meetings (2001, 2003 and 2005).

As a senior executive with Hagler Bailly Consulting, he co-managed the North American utility practice for this 500 person international consulting firm. He also helped establish Electronic

DANIEL M. VIOLETTE

Data Systems Management Consulting Services' (EDS-MCS) practice in the energy industry. Both at Summit Blue and in these previous positions, Dr. Violette has led teams of consultants and subcontractors in the performance of assignments for energy companies and related network industry trade allies, public utility commissioners, consumer groups, state collaboratives, and international agencies such as the World Bank, the International Energy Agency (IEA), and the Asian Pacific Economic Cooperation (APEC) organization. Dr. Violette has worked on assignments in Pakistan, Hungary, and the Philippines as well as leading key tasks for a 12-member consortium of countries on the IEA's Demand Side Programme.

Dr. Violette served three elected terms as the President of the Association of Energy Services Professionals (AESP) and two terms as Vice Chair of the Peak Load Management Alliance (PLMA). He currently is on the Board of Directors of both organizations. Dr. Violette has published over 40 papers in journals and books, made over 60 contributions to published conference proceedings, and contributed to reports to the U.S. Congress prepared by the Department of Energy, the National Acid Precipitation Assessment Panel (NAPAP), and the National Commission on Air Quality (NCAQ).

SELECTED ASSIGNMENTS

- Currently working on the design and evaluation of NSTAR's Smart Grid Pilot Program in response to the legislation passed by the Massachusetts State Legislature.

- Completing a review of BC Hydro's 2008 DSM Plan on behalf of the Electricity Conservation and Efficiency Advisory Committee in British Columbia.

- Served as expert staff to the California Public Utilities Commission on evaluation methods for demand response (DR) programs and approaches for assessing the cost-effectiveness of DR programs (2007-2008).

- Evaluated Hydro One's Double Returns Peak Load Reduction program (2008).

- Led a DSM technical potential study for Con Ed focused on peak reduction and dispatchable reduction technologies (2008).

- Currently working with three utilities on the development of evaluation plans for DSM programs and portfolio's including recent large-scale programs for all three IOUs in California.

- Leading the implementation of the evaluation of New York State Energy Research and Development Authority's (NYSERDA) utility-SBC funded DSM and DR programs as part of a five-year contract awarded as a follow-on to a prior four year effort on DSM evaluation of programs spanning all sectors, including the evaluation of the NYSERDA's new DSM technology development program. (2006- 2008)

DANIEL M. VIOLETTE

- Dr. Violette is the lead workshop facilitator for Public Service Company of New Mexico Integrated Resource Planning collaborative process and consultant to the utility on integration of DSM programs into the IRP. (2006-2007)

- Dr. Violette is currently leading Summit Blue's work in support of the California Energy Commissions Working Group 2 (WG2) Monitoring and Evaluation Subcommittee which involves an impact evaluation all three California IOUs DSM and price-responsive load programs for program years 2004 and 2005. This is a multi-year effort assessing demand bidding programs and critical peak pricing programs for customers with over 200kW demand. (Jan 2005 - May 2006)

- Dr. Violette served as a consultant / facilitator to the IRP stakeholders collaborative supporting the development of Idaho Power's 2006 integrated resource plan. (Planned end July 2006)

- Leading the impact evaluation and overseeing the process and operational assessment of Public Service Electric &Gas (PSE&G) company's myPOWER innovative pricing pilot program spanning three years and addressing TOU, CPP and day-ahead RTP rate designs. (Year 1 report completed, 2006 work on-going)

- Project manager for a multi-year, multi-million dollar DSM evaluation, market characterization, market assessment and causality/attribution study covering the energy efficiency, demand response and market transformation programs offered by the New York State Energy Research Development Authority (NYSERDA). Over 50 demand-side programs spanning energy efficiency, peak load management, renewables, metering and combined-head and power programs were examined in this evaluation effort. (Separate awards for the 2003 to 2004 program years, and a contract extension for the 2005 program year, and a recent renewal for the 2006 program year).

- Dr. Violette just concluded a project for the California Energy Commission's PIER (Public Interest Energy Research) Program where he worked on the development of A Comprehensive framework for assessing the value of demand response programs including both load-reduction and price-response programs. (Completed March, 2006)

- Leading a comprehensive market assessment of energy efficiency programs implemented by the eight electric and gas utilities in New Jersey on behalf the Office of Clean Energy, New Jersey Board of Public Utilities. (2005 – 2006)

- Dr Violette is leading a Summit Blue assignment working with Hawaiian Electric Company to design Commercial/Industrial Voluntary Load Control (CIVLC) Programs Development. Summit Blue is designing a suite of demand response program offerings for HECO's commercial and industrial customers as an alternative to the company's current direct load control program. The Summit Blue team is reviewing customer data, conducting customer focus groups, and interviewing utility dispatchers and key account representatives to develop several program options that are appropriate for various customer types and sizes. The program will allow participants to choose the offering that is best suited to their operational needs and preferences regarding technology, flexibility, financial incentives, and other considerations. Summit Blue is also preparing a business case that includes an economic rationale for the program and that will form the basis of HECO's application for PUC approval of the program. (on-going)

- Throughout 2004, Dr. Violette led the evaluation planning and implementation for the assessment of the New York State Energy Research and Development Authority's SBC (System Benefit Charge) funded programs across residential, commercial, and industrial sectors including energy efficiency, load response, renewables and combined heat and power programs. This initial year effort led to two additional years being added to the contract. (2004)

- Working with the Sacramento Municipal Utility District to evaluate the impacts of a smart thermostat program among residential customers for Summer 2002 and to design and assess a combined Smart Thermostat program and TOU rates offer to encourage both energy efficiency and demand response (2002-2004)

- Working on a project for the Board of the Northwest Energy Efficiency Alliance examining the portfolio of programs being implemented by the NW Alliance to determine if the objectives of the Alliance have been achieved, whether benefits that were expected to occur from a regional implementation organization are being achieved, and whether the overall value of the Alliance can reasonably be assumed to be exceeding its costs (2003).

- Conducting an evaluation of a mass market program for small businesses for the Massachusetts DSM Collaborative. The program is being offered by NSTAR and involves audits, equipment installation and load control equipment. Impact, process and market evaluations are being conducted in this ongoing assessment (October 2002 to February 2003)

- Worked with the Energy research Centre of the Netherlands to develop the verification protocols for bids for Joint Implementation and Clean Development Mechanisms for cross country investments in carbon emission reduction strategies (January, 2002)

- Developed verification and evaluation protocols for energy efficiency projects designed to reduce emissions of greenhouse gases across a wide variety of programs for the International Energy Agency (IEA) and led a workshop in Denmark on this topic (May, 2001)

- Leading the implementation of process and impact evaluations using both engineering and econometric techniques to evaluate seven DSM programs for LG&E Energy and Kentucky Utilities. Data being used includes selected samples of end-use metered data, billing data, audit data, and survey data (Fall, 2001).Implementing evaluation efforts for seven programs at LG&E Energy and KU Utilities

- Worked with American Electric Power (AEP) Companies retail pricing group along with its subsidiary utilities Public Service Company of Oklahoma and Central and Southwest utilities to design innovative retail pricing strategies for the opening of the Texas market to retail choice.

- Designed peak load curtailment programs for Louisville Gas & Electric Company and developed evaluation plans for a portfolio of energy efficiency programs (2000).

Selected Project Activities 1990 to 2000:

- Led a number of projects for the Electric Power Research Institute, including developing and conducting training courses on performance measurement, data collection for decision making, authoring a handbook for assessing the performance of energy services programs.

- Led a three-year in-field metering and monitoring for a consortium of seven gas utilities in New England estimating the impacts of energy efficiency equipment in the residential and commercial sectors.

- Led an effort for a consortium of five New England utilities to examine the influence of utility actions on regional energy use and the markets for energy products (1.

- Coauthored a "White Paper" for the National Association of Regulatory Utility Commissioners on regulatory issues in the evaluation of energy services programs.

- Managed the analytic tasks of an EPRI tailored collaborative project examining the integration of information from short-term metering of technologies with longer term billing analyses of customers. The participating utilities were Northern States Power and Madison Gas and Electric Company.

- Performed a number of assignments for utilities assessing their customer information systems and how they can be used for performance measurement and market research. These efforts often included the development of strategies for the collection of customer data and market intelligence.

- Designed and conducted training programs and workshops on market and resource planning, as well as performance measurement for a number of utilities. These seminars and workshops have been conducted for professionals at San Diego Gas and Electric Company, Ontario Hydro, Bonneville Power Administration, Hydro Quebec, Public Service Electric & Gas, Arizona Public Service Company, and other utilities. Dr. Violette has also produced and conducted six training seminars on behalf of the Electric Power Research Institute.

- Developed environment strategies, including environmental externality valuation and integration of externalities in utility plans, as well as a number of assignments related to

Clean Air Act compliance, including emissions trading, conservation as a compliance strategy, and the evaluation of compliance plans.

SELECTED PUBLICATIONS — JOURNALS AND BOOKS

"AMI and Demand Response – Getting it right the first time!" with Ross Malme and Pete Scarpelli, Public Utilities Fortnightly, July 2006

"Metering: Calm at a Technology Crossroads" Energy Markets, Vol. 10, No. 3, April 2005

AESP/EPRI Pricing Conference: What's Working and What's Needed; White Paper, EPRI Value and Risk Program; Daniel Violette, Ahmad Faruqui and Brent Barkett: Prepared for: Victor Niemeyer Area Manager, Power Markets, published by EPRI, December 2004m #1008530

"Demand Response as a Driver of Innovation and New Technology" with Ross Malme, Electricity Today, Issue 8, Volume 16, 2004

"*Electricity Pricing -- Lessons from the Front"* White Paper Based on: The AESP/EPRI Pricing Conference: Innovation, Technology, Economics and Markets; Violette, Daniel and Ahmad Faruqui; Prepared for: Victor Niemeyer Area Manager, Power Markets, published by EPRI, October 2003, #1002223

"Implications of Retail Customer Choice for Generation Companies" in Customer Choice: Finding Value in Retail Electricity Markets, Faruqui, A. and J. R.Malko, Eds., Published by Public Utility Reports, ISBN#: 0-910325-73-1, 2003.

"Strategic Alliances: Partnering to Achieve Cooperative Objectives," published by the National Rural Electric Cooperative Association (NRECA), October 2003, #Project01-06

"Retrospective Assessment of the Northwest Energy Efficiency Alliance" Published by the Northwest Energy Efficiency Alliance, October 2003, #E03-120

"Rationalizing Prices in Retail Markets" Energy Markets, Hart's Publications, April Issue, 2003.

"Demand Response: Creating Customer and Market Value," with L. Barrett, White Paper Series, Published by the Peak Load Management Alliance, October, 2002.

"Making Demand Response a Reality", with Larry Barrett, Energy User News, Aug. 2002, Vol. 27, No. 8.

"*Price-Responsive Load among Mass-Market Customers*," in Electricity Pricing in Transition, A. Faruqui and K. Eakins, eds., Kluwar Academic Publishers, Norwell, MA, 2002

"Demand Response: Principles for Regulatory Guidance" with Larry Barrett, White Paper Published by the Peak Load Management Alliance, February 2002.

DANIEL M. VIOLETTE

"An Initial View on Methodologies for Emission Baselines: Energy Efficiency Case Study," Published by OECD and IEA, June 2000

"*Conventional Pricing Wisdom Not Competitive: Riding Customer-Choice Wave with Innovation Creates Margin, Attracts Customers,*" for Energy Marketing, February 1999, Volume 2 Issue 1.

"Conventional Pricing Wisdom Not Competitive: Riding Customer-Choice Wave with Innovation Creates Margin, Attracts Customers," for Energy Marketing; Forecasting the Future of the Energy Marketplace, February 1999/Volume 2.1.

"Chapter 16: Implications of Retail Customer Choice for Generation Companies." In Customer Choice: Finding Value in Retail Electricity Markets, published by Public Utility Reports (PUR) Press, January 1999.

"Evolving Business Processes for Gas Utilities: The Impacts of Retail Choice," published by the Gas Research Institute, Market Analysis and Information Technology Business Unit, May 1998.

"Retail Choice and Energy Convergence: Implications for Gas Utilities," Natural Gas, Pubs., John Wiley & Sons, Inc., August 1998.

"Evaluation, Verification, and Performance Measurement of Energy Efficiency Programmes." *International Energy Agency Publication*, Paris, France, Forth Draft, April 25, 1996.

Editor, Performance Impacts: Evaluation Methods for the Nonresidential Sector**,** Electric Power Research Institute Pubs., Palo Alto, CA, EPRI TR-105845, Research Project 3269, December 1995.

Editor, Inaugural Issue of the Energy Services Journal, Lawrence Erlbaum Associates Pubs., Vol. 1, Issue 1, October 1995.

"Chapter 6: Estimating Spillover and Market Transformation." In Performance Impacts: Evaluation Methods for the Nonresidential Sector, Electric Power Research Institute Pubs., Palo Alto, CA, EPRI TR-105845, Research Project 3269, December 1995.

Evaluation and Verification of Energy Efficiency Programmes: Issues and Methods, International Energy Agency Pubs., Paris, France, October 1995.

"A Convergence of Concepts: The Coming Wave of Change Management and Strategic Benchmarking." President's Column, STRATEGIES: A Publication of the Association of Energy Services Professionals, Spring 1995, p. 9.

"Demand-Side Management at the Crossroads," Natural Gas Journal, Pubs: John Wiley & Sons, Inc., December 1994, pp. 13-18.

"DSM in the Crystal Ball." President's Column, STRATEGIES: A Publication of the Association of Energy Services Professionals, Fall 1994, p. 7.

Regulating DSM Program Evaluation: Policy and Administrative Issues for Public Utility Commissions. National Association. of Regulatory Utility Commissions, (NARUC), Washington, DC, NTIS Pubs. #ORNL/Sub/95X-SH985C, April 1994.

"Comments on Applying Ratio Estimation Methods." Evaluation Exchange. Synergic Resources Corporation and the International Energy Program Evaluation Conference Pubs., Bala Cynwyd, PA, September/October 1993, Vol. 3, No. 2, p. 3.

"Chapter 4: Value of a Statistical Life in Wrong Death Cases," Hedonic Methods in Forensic Economics, J. Ward Ed., University of Missouri Press Pubs., 1992.

"Setting Evaluation Accuracy Standards: What Will and Will Not Work." Evaluation Exchange. Synergic Resources Corporation and the International Energy Program Evaluation Conference Pubs., Bala Cynwyd, PA, November/December 1992, Vol. 2, No. 6, p. 9.

Approaches for Synthesizing DSM Program Evaluations: The Wisconsin DSM programs Evaluation Database and a Review of Meta-Analysis, Electric Power Research Institute Pubs., Palo Alto, CA, #EPRI, TR-100697s, Vols. 1-3, June 1992.

"Chapter 5: Data Analysis for DSM Program Evaluation," in the Handbook to DSM Program Evaluation, Eric Hirst and John Reed, eds., NTIS Pubs., Washington, DC, # ORNL/CON -336, December 1991.

"Chapter 9: Integrated Resource Planning and the Clean Air Act:" Energy Efficiency and the Environment: Forging the Link, E. Vine, D. Crawley and P. Centolella, eds., ACEEE Series on Energy Conservation and Energy Policy, Pubs: American Council for an Energy-Efficient Economy Pubs., Washington, DC, 1991, pp. 177-188.

Impact Evaluation of Demand-Side Management Programs — Volume 2: Case Studies and Applications, Electric Power Research Institute Pubs., Palo Alto, CA, #EPRI CU-7179 V2, September 1991.

Impact Evaluation of Demand-Side Management Programs — Volume 1: A Guide to Current Practice, Electric Power Research Institute Pubs., Palo Alto, CA, #EPRI CU-7179, Vl, February 1991.

Integrated Planning, Evaluation and Cost Recovery Issues for Gas Distribution Utilities, Planning and Analysis Group, American Gas Association Pubs., May 1991.

SELECTED CONFERENCE PRESENTATIONS AND PAPERS

"Review of BC Hydro's 2008 DSM Plan." Prepared for: BC Hydro's Electricity Conservation and Efficiency Advisory Committee, Summit Blue Consulting, January 22, 2009

"Energy Efficiency and Demand Response." Peak Load Management Alliance (PLMA) Fall Conference, Austin, Texas, October 28-29, 2008.

"2008 Electric Cooperative Rate Conference: Demand-Side Management and Demand Response." Kentucky International Convention Center, Louisville, Kentucky, October 28, 2008

"Demand Response and Energy Efficiency – Issues and Trends," ECUI Conference on Demand Response and Energy Efficiency Canada, Toronto, Canada, October 9-10, 2008.

"Estimate It, Measure It, Verify It." National Town Meeting on Demand Response, Demand Response Coordinating Committee (DRCC), Washington, D.C., June 2-3, 2008.

"Demand Response in Organized Electric Markets – Comments by Daniel M. Violette." at Federal Energy Regulatory Commission (FERC) Technical Conference, May 21, 2008.

"Load-Impact Estimation and Cost-Effectiveness Rulemaking in California -- Working Towards Recommendations." Proceedings of National Energy Services Conference, Association of Energy Services Professionals, January 28-31, 2008

"*Integrating Demand Side Resource Evaluations in Resource Planning – An Industry Turning Point*" in Proceedings of the International Energy Program Evaluation Conference (IEPEC) Proceedings, August, 2007, and Presenter at Meetings August 14-16, 2007.

"*Developing Protocols to Estimate Load Impacts from Demand Response Programs and Cost-Effectiveness Methods -- Rulemaking Work in California*" in Proceedings of the International Energy Program Evaluation Conference (IEPEC) Proceedings, August, 2007, and Presenter at Meetings August 14-16, 2007.

"Select Issues in Attribution and Net-to-Gross – Practical Examples." Presented at: CALifornia Measurement Advisory Council (CALMAC) Meetings, July 18, 2007

"*Joint Regulatory Dialogue on: Energy Efficiency/Demand-Side Management,"* Presenter and Panel Member, Canadian Electric Association, Montreal, Canada, April 2007.

Speaker, "Demand-Side Management" at CAMPUT's 2006 Conference and Annual General Meeting, Fairmont Algonquin Hotel, St. Andrews, New Brunswick, September 10-13, 2006.

"Demand-Side Management Regulatory Issues" Presented at the Canadian Association of Members of Public Utility Tribunals (CAMPUT) Regulatory Key Topics Meeting, Ottawa, CA, March 2006

"Demand Response in Resource Planning." Panel discussion at the Peak Load Management Alliance Spring 2006 Conference: A Critical Update on Demand Response, Washington, D.C., March 2006

"Protocol Development for estimating load impacts of DR" California Public Utility Commission and the California Energy Commission Workshop on Benefit Cost Analyses of Demand Response Programs, San Francisco, CA, March 2006

DANIEL M. VIOLETTE

"Framework for Non-Energy Benefits in the Next Generation of Evaluation and Program Design" Proceedings of the 16th National Energy Services Conference: Market Transformation, Research and Evaluation Track, San Diego, February 2006

"A Comprehensive/Integrated DR Value Framework" presented at the Demand Response Research Center TAG Technical Advisory Group Meeting, San Francisco, CA, January 2006

"Valuing Demand Response – An Integrated Resource Planning Approach," presented at the U.S. Demand Response Coordinating Committee's National Town Meeting on Demand Response II, Washington, D.C., January 2006

"Valuing Demand Response – An Integrated Resource Planning Approach," prepared for DistribuTECH 2006, Tampa, Florida February 2006

"Valuing Demand Response in Resource Planning," Technology Symposium: What's New in Demand Response and Energy Efficiency, Proceedings of the Association of Energy Professionals Irwindale, CA, November 2005

"Incorporating Climate Change into Resource Planning," Presented at "Identifying Research to Help Electric Companies Adapt to Climate Change" Sponsored by EPRI , Arlington, VA, October 2005

"Valuing Demand Response Resources in Resource Planning," Proceedings of the International Demand Response Seminar, CEC PIER Demand Response Research Center and the IEA Demand-Side Management Programme, February 4, 2005.

"IEA Task XIII: Demand Response Resources Assessment" Peak Load Management Alliance (PLMA) Spring Meeting, San Diego, CA; March 2004

"NW Energy Efficiency Alliance: Retrospective Evaluation," Eighth National Symposium on Market Transformation, Washington, D.C. -- March 2004

"Portfolio Analysis of Demand-Side Resources (DSR) – Role in Planning," presented at the Eighth Annual National Symposium On Market Transformation, Washington DC, March 1st-2nd, 2004

"Making Electricity Markets Work for Everyone," presented at the 2004 Center for Neighborhood Technology and The Community Energy Cooperative Forum, Chicago, IL, February 27, 2004.

"The Natural Gas Crisis - Implications for EE & DR Cost-Effectiveness Analysis," presented at the 14th National Energy Services Conference and Exposition for the Association of Energy Professionals, New Orleans, December 10-12, 2003

"State Regulatory Activity On Time-Differentiated Electricity Pricing Programs," Proceedings of the AESP National Energy Services Conference, New Orleans, December 2003.

DANIEL M. VIOLETTE

"Assessment Of Demand Response Options – A Distribution Company View." Proceedings of the AESP National Energy Services Conference, New Orleans, December 2003.

"Mass-Market DR Offerings: Evaluation Methods Assessment and Results" *Proceedings of the International Energy Program Evaluation Conference,* Seattle, WA, August 2003.

“Pricing in Retail Markets — Innovation and Resource Allocation,” presented at the 2003 Pricing in Electricity Markets Conference for the Association of Energy Professionals, in conjunction with EPRI, Chicago, IL, May 14-15, 2003.

"DR Strategic Assessment: A DISCO Perspective" *Peak Load Management Alliance Spring Meetings*, Arlington VA, March 2003.

"Demand Response: Infrastructure and Design Principles*" in Enhancing Demand Response in Liberalised Electricity Market*, Paris, France, February, 2003

“Cost Effective Evaluation of Mass Market Load Management Programs” In P*roceedings of the 2001 International Energy Program Evaluation Conference*, Salt Lake City, UT, NTIS Pubs., Washington, DC, July 2001.

“Opportunities for Load Management in Mass Markets,” EEI Retail Energy Services Conference**,** Chicago, Ill., March 29, 2001

“Innovative Sales and Pricing Structures — Riding the Waves!”, presented at EMACS ’98: The 1998 Energy Marketing and Customer Service Conference, The Westin Horton Plaza, San Diego, California, October 15, 1998.

“Convergence of Markets Opportunities and Risks,” presented at the American Gas Association’s (AGA) Workshop on Unbundling and Affiliate Transactions, Ritz-Carlton Hotel, Arlington, VA, July 9, 1998.

“Convergence - reality or hype?,” presented at the Electric Utility Consultants conference on Electric Utility Business Environment, Westin Hotel, Denver, CO, June 24, 1998.

“Stranded Cost Recovery — Understanding the Legislation Affecting New Jersey and States Around the Country,” presented at the IBC’s Fourth Annual Industry Forum on Developing and Negotiating Strategic Mechanisms for Stranded Cost Recovery, Renaissance Washington DC Hotel, Washington, DC, June 23, 1998.

“Electricity Price Forecasts and the Forward Price Curve for Electricity,” presented at the EPRI 1998 Innovative Approaches to Electricity Pricing Conference, Washington, DC, June 18, 1998.

“The Business Process Challenges of Retail Competition: Organizational Structures Will Change,” Pacific Cost Gas Association’s (PCGA) Deregulation Conference, Portland, OR, May 13, 1998.

"Changing Times: Business Opportunities and Risks in the Gas and Electric Industries." Presented at the American Gas Association's (AGA) Marketing and Communications Conference: Betting On Our Customers, Las Vegas, NV, April 27, 1998.

"The Ten Year Perspective: What Actions Need to be Taken Today for Your Firm to be Successful 10 Years From Now?" Presented at *The Fourth Annual Power Industry Forum, Panel Four: Marketing — Heart of the New Power Company*, Infocast, Carlsbad, CA, March 7, 1997.

"North American Energy Measurement & Verification Protocols (NEMVP)." Presented at the AEE Chapter, Budapest, Hungary, November 26, 1996.

"Evaluation of Energy Efficiency Activities: The Keys to Success." Conference materials presented at the *2nd International DSM & Energy Efficiency Strategies Conference*, Copenhagen, Denmark. November 20-21, 1996.

"An Introduction to the Principles and Applications of Market Research for Electric Power Companies." In *Infocast Conference Proceedings — Market Intelligence for Utilities: Obtaining and Analyzing Critical Customer and Competitor Data*." Denver, CO, July 29, 1996.

"Customer Decision Making." Presentation for *Infocast Conference — The Marketing Institute for the Electric Power Industry*, Atlanta, GA, March 5, 1996.

"Creating Market Opportunities through Energy Services." Opening Plenary Session, *Proceedings of the 1995 Association of Energy Services Professionals Annual Member Meeting*, Association of Energy Services Professionals Pubs., Boca Raton, FL, December 4-6, 1995.

"Customers' Speak — What Customers Need from Energy Suppliers." In *Proceedings of the 1995 Association of Energy Services Professionals Annual Member Meeting*, Association of Energy Services Professionals Pubs., Boca Raton, FL, December 4-6, 1995.

"Assessing Marginal Costs for Competitive Pricing." In *Proceedings of Conference on Competitive Analysis & Benchmarking for Electric Power Companies*, Center for Business Intelligence Pubs., Burlington, MA, November 1995.

"Performance Measurement Concepts and Framework." In *The 1995 Performance Measurement Workshop: Measuring the Performance of Utility Products and Services in an Era of Increasing Competitiveness*, Denver, CO, Electric Power Research Institute Pubs., Palo Alto, CA, November 1995.

"Setting a Research Agenda for Assessing Market Transformation and Spillover," In *Proceedings of the 1995 International Energy Program Evaluation Conference*, Chicago, IL, NTIS Pubs., Washington, DC, #CONF-950817, August 1995, p. 9.

"Evaluation in the Age of Anxiety." In P*roceedings of the 1995 International Energy Program Evaluation Conference*, Chicago, IL, NTIS Pubs., Washington, DC, #CONF-950817, August 1995, p. 859.

"Data Collection and Information Systems: What We've Learned from the DSM Experience." In *Proceedings: Delivering Customer Value — 7th National Demand-Side Management Conference*; Electric Power Research Institute Pubs., Palo Alto, CA, #EPRI TR-105196, June 1995, p. 25.

"Energy Efficiency Evaluation." In *Proceedings — IEA Experts Panel Meeting on Evaluation*, Sponsor: International Energy Agency/Organization for Economic Co-operation and Development, Washington, DC, November 1994.

"Evaluation: Issues, Methods, and Direction." In *Proceedings of Asian Pacific Economic Community (APEC) Inter-Utility Demand Side Management Liaison Group*, Julia Shaver, ed., Oak Ridge National Laboratory, Oak Ridge, TN, October 1994.

"Addressing Uncertainty and the Value of Flexibility in the Second Generation of IRP." Published in the *Proceedings of American Council for an Energy Efficient Economy — 1994 Summer Workshop***,** ACEEE vol. 6, p. 231, August 1994.

"The Treatment of Outliers and Influential Observations in Regression-Based Impact Evaluation." Published in the *Proceedings of American Council for an Energy Efficient Economy — 1994 Summer Workshop***,** ACEEE vol. 8, p. 172, August 1994.

"Addressing Uncertainty and the Value of Flexibility in Utility Planning." In *Proceedings of the 1994 Integrated Resource Planning Conference*, Electric Utility Consultants, Inc. Pubs., Denver, CO, April 1994, p. 1.

"Discrete Choice Models for Planning and Evaluation of Electric Utility Demand-Side Management Programs," *Proceedings TIMS/ORSA Joint National Meeting*, Chicago, IL, May 1993.

"Data Quality in Program Tracking Systems: The Impact on Evaluation." *Proceedings of the 6th National Demand-Side Management Conference*; Electric Power Research Institute Pubs., Palo Alto, CA, #EPRI TR-102021, March 1993.

"Impact Evaluation and Program Tracking Systems." *Proceedings — 6th National Demand-Side Management Conference: Making a Difference.* Sponsors: Electric Power Research Institute, Edison Electric Institute, and U.S. DOE, Electric Power Research Institute Pubs., Palo Alto, CA, #EPRI TR-102021, March 1993, p. 41.

"Uncertainty in an IRP Process." *Proceedings of the Integrated Resource Planning Conference*, Sponsor: Electric Utility Consultants, Inc., Denver, CO, March 18-19, 1993, p. 289.

"Estimating the Impacts of DSM Programs for Use in IRPs." *Conference Proceedings — Long Range Forecasting for Gas Utilities*, New Orleans, LA. Sponsor: American Gas Association, Washington, DC, March 11-13, 1992.

"A Framework for Evaluating Environmental Externalities in Resource Planning — A State Regulatory Perspective." In *Proceedings of the NARUC National Conference on Environmental*

Externalities in Jackson Hole, WY. National Association of Regulatory Utility Commissioners, Washington, DC, October 1990.

“Five Steps through the Clean Air Act — Developing an Acid Rain Compliance Strategy.” In *Proceedings of the 1990 Energy and the Environment Conference*. Sponsor: Electric Utility Consultants, Inc., Denver, CO, September 1990.

“Using Billing Data to Estimate Energy Savings: Specifications of Energy Savings Models, Self-Selection and Free-Riders.” Published in the *Proceedings of American Council for an Energy Efficient Economy (ACEEE) — 1990 Summer Workshop*, ACEEE, Washington, DC, August 1990, Vol. 6, p. 131.

“Evaluation of a New Home Construction Program: Combining Load Research, Billing Data, and Engineering Estimates in a Consolidated Framework.” Published in the *Proceedings of American Council for an Energy Efficient Economy (ACEEE) — 1990 Summer Workshop,* ACEEE, Washington, DC, August 1990, Vol. 6, p. 167.

“Use of End-Use Load Research Data in Statistical/Econometric Evaluations of DSM Programs.” *Proceedings — Conference on End-Use Load Information and its Role in DSM* in Irvine, CA. Sponsor: The Fleming Group, July 1990.

CONSULTING REPORTS

“Revised Sampling Methodology for Engineering Reviews of Custom Projects” prepared for Enbridge Gas Distribution Inc., October 2008.

“Energizing Virginia: Efficiency First” with American Council for an Energy-Efficient Economy, Summit Blue Consulting, ICF International, and Synapse Energy Economics, prepared for ACEEE, Report Number E085, September 2008.

“Impact and Process Evaluation of the Double Return Program” prepared for Hydro One Networks Inc., June 2008.

“Con Edison Callable Load Study” prepared for Con Edison, May 2008.

“Sampling Methodology for Engineering Reviews of Custom Projects” prepared for Enbridge Gas Distribution Inc. and Union Gas Ltd – A Spectra Energy Co., April 2008.

“Final Report for the myPower Pricing Segments Evaluation,” Prepared for Public Service Electric and Gas Company, December 2007.

“A Commitment to Serve: A Cooperative Board Member’s Guide to G&T Resource Planning” with Jane Pater, prepared for Western Resource Advocates, November 2007.

“Energy Efficiency: the First Fuel for a Clean Energy Future – Resources for Meeting Maryland’s Electricity Needs” prepared for ACEEE, Report Number E082, February 2008.

DANIEL M. VIOLETTE

10. "New Jersey Central Air Conditioner Cycling Program Assessment – Final Report" with Jeff Erickson and Mary Klos prepared for Atlantic City Electric, Jersey Central Power & Light, and Public Service Electric & Gas, June 2007.

"New Jersey Central Air Conditioner Cycling Program Assessment" prepared for Atlantic City Electric, Jersey Central Power & Light, and Public Service Electric & Gas, June 2007.

"Avoided Cost Analysis for Energy Efficiency Programs" with Rachel Freeman, prepared for Kansas City Power and Light, Highly Confidential, March 2007.

"Evaluation of 2005 Statewide Large Nonresidential Day-Ahead and Reliability Demand Response Programs – Final Report" with Quantum Consulting, Inc. and Summit Blue Consulting, LLC prepared for Working Group 2 Measurement and Evaluation Committee, P2037, April 2006

"Evaluation of the 2005 Energy-Smart Pricing Plan^{SM}" prepared for the Community Energy Cooperative, April 2006

"Protocols for Estimating the Load Impacts From DR Program" with Quantum Consulting Inc, prepared for Working Group 2 Measurement and Evaluation Committee, April 2006

"Development of A Comprehensive/Integrated DR Value Framework" prepared for the Demand Response Research Center, California Energy Commission, Public Interest Energy Research (PIER) Program, March 2006.

"Interim Report for the First Season of the myPower Link Utility Activated Load Management Pilot Program" with Jeff Erickson and Michael Ozog, prepared for Public Service Electric and Gas Company, February 2006.

"Demand-Side Management: Determining Appropriate Spending Levels and Cost-Effectiveness Testing" co authored with the Regulatory Assistance Program, prepared for Canadian Association of Members of Public Utility Tribunals, January 2006.

"DRR Valuation and Market Analysis; Volume I: Overview" with Rachel Freeman and Chris Neil, prepared for International Energy Agency Demand-Side Programme, Task XIII: Demand Response Resources Task Status Report, January 2006.

"DRR Valuation and Market Analysis; Volume II: Assessing the DRR Benefits and Costs" with Rachel Freeman and Chris Neil, prepared for International Energy Agency Demand-Side Programme, Task XIII: Demand Response Resources Task Status Report, January 2006.

"Quick-Hit DR Programs: A Case Study of California's 20-20 Program" prepared for Ontario Power Authority, October 2005.

"Program Design for Commercial and Industrial Voluntary Load Control Programs" with Stuart Schare, prepared for Hawaiian Electric Company Inc, September 2005.

DANIEL M. VIOLETTE

“Estimating Demand Response Market Potential” with Randy Gunn prepared for the International Energy Agency Demand Side Management Programme, Task XIII: Demand Response Resources, July 2005.

“Commercial/Industrial Performance Program (CIPP); Market Characterization, Market Assessment and Causality Evaluation” prepared for The New York State Energy Research and Development Authority (NYSERDA), March 2005.

“New Construction Program (NCP); Market Characterization, Market Assessment and Causality Evaluation” prepared for The New York State Energy Research and Development Authority (NYSERDA), March 2005.

“Working Group 2 Demand Response Program Evaluation – Program Year 2004” with Quantum Consulting Inc, prepared for California Energy Commission Working Group 2 Measurement and Evaluation Committee, December 2004, P1996.

“Evaluation of the 2004 Energy-Smart Pricing Plan^{sm}” prepared for the Community Energy Cooperative, March 2005.

"Impact Evaluation of the Power Choice Program" prepared for Sacramento Municipal Utility District, California Energy Commission PIER program, January 2004.

"Phase 1 Market Characterization Market Assessment and Causality: New Construction Program" prepared for New York State Energy Research and Development Authority, May 2004.

“Findings and Report: Retrospective Assessment of the Northwest Energy Efficiency Alliance” with Kevin Cooney and Michael Ozog, prepared for Northwest Energy Efficiency Alliance, December 2003.

TESTIMONY / LITIGATION

- “Staff Guidance for Straw Proposals on: Load Impact Estimation From DR and Cost-Effectiveness Methods for DR,” Prepared for: Energy Division, CPUC Demand Analysis Office. May 24, 2007

- Direct Testimony on behalf of Piedmont Environmental Council before the State Corporation Commission of Virginia; Case Nos. PUE-2007-00031 and PUE-2007-00033 addressing “Summit Blue Expert Paper: Demand-Side Management for the Commonwealth of Virginia, December 4, 2007.

- Prepared Testimony with Testimony scheduled July 2006, *Appropriate DSM Incentives and Alignment with Policy Objectives*, written rate case testimony submitted to the Hawaii Public Utilities Commission on behalf of Hawaiian Electric Company, HECO T-12, Docket No. 04-0113.

- Assisting in the development of load management rates that are expected to be filed as part of Hawaiian Electric Company's current rated case before the Hawaiian Public Utilities Commission, Docket No. 04-0113.

- Expert Report prepared for Constellation NewEnergy, Inc. United States District Court Eastern District of Pennsylvania, Civil Action No. 02-CV-2733, May 2004 related to demand response / load management programs and technologies.

- Prepared testimony and testified before the New Jersey Board of Public Utilities concerning GPU's Restructuring Petition, Docket No. EO97060396, March 20, 1998. Corresponding report is entitled "Review of GPU's Restructuring Petition, GPU Energy Docket No. EA97060396, February 24, 1998.

- Prepared testimony and testified before the New Jersey Board of Public Utilities concerning GPU Energy Unbundled Rates Petition, Docket No. EO97070458," January 12, 1998. Corresponding Report is entitled "Review of GPU's Unbundled Rates Petition," GPU Energy Docket No. EA97060396, December 15, 1997.

- Prepared testimony in the Joint Application of Central Power and Light Company, West Texas Utilities Company and Southwestern Electric Power Company for Approval of Preliminary Integrated Resource Plans and for Related Good Cause Exceptions, before the Public Utility Commission of Texas, Docket No. 16995, January 1997.

- Participated in rate case testimony and support for Central Light and Power Company for the rate case, Docket No. 14965, before the Texas PUC, March 1996.

- Prepared testimony for three utilities in Iowa on DSM evaluation, incentives and IRP.

- Authored testimony on behalf of El Paso Electric Company examining the efficacy of its supply planning process as part of an ongoing rate case concerning in part, the cost recovery of the Palo Verde 3 Nuclear Power Plant.

- Prepared testimony for Peoples Natural Gas concerning the impact evaluation of five energy efficiency programs, November 1993.

- Provided litigation support for the Municipal Electric Association of Canada, in hearings in Ontario concerning Ontario Hydro's commitments to nuclear facilities, utility planning methods, and load forecasting. This multiyear assignment involved the most thorough review of Ontario Hydro's planning process, the future of nuclear power in Canada, and the role of independent power producers. The hearings were presided over by an Ontario Province supreme court justice. (1991-1992)

- Rebuttal testimony on behalf of Arizona Public Service Company involving utility planning and rate increase procedures, before the Arizona Corporation Commission, January 1991, Docket Nos. U-1345-900007 and U-1345-89-162.

- Prepared testimony on behalf of El Paso Electric pertaining to its planning and resource acquisition process, filed in October 1990 before the Texas Commission.

DANIEL M. VIOLETTE

- Testimony on cost of service, innovative rates, and rate design before the Connecticut Department of Public Utility Control RE: United Illuminating Company, Docket No. 89-08-11 and 12.

- Surrebuttal testimony for the staff of the Delaware Public Service Commission, "Concerning the Power Plant Performance Program of Delmarva Power & Light Company," Docket No. 88-16, March 1989.

- Testimony for the staff of the Delaware Public Service Commission, "Review of the Delmarva Power & Light Company Power Plant Performance Program," Docket No. 88-16, November 1988.

- Testimony on Arizona Public Service Company, Cost of Service and Rate Design, for the staff of the Arizona Corporation Commission, Docket No. U-1345-85-150, January 1987.

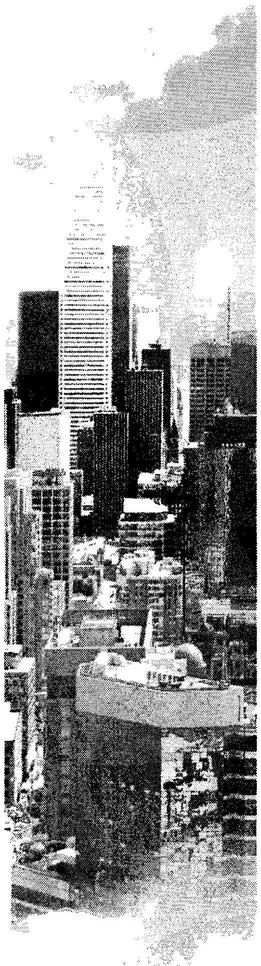
Between 1983 and 1987, testified in eleven regulatory proceedings covering a-range of topics.

EDUCATION

- University of Colorado, PhD, Economics, 1980
  (Honors: Fields of Industrial Organization and Econometrics)
- University of Colorado, MS, Economics, 1974
- Arizona State University, BS, Economics, 1973
  (Summa Cum Laude)

PROFESSIONAL AFFILIATIONS AND HONORS

- Served three elected terms (1994, 1995, and 1996) as the President of the Association of Energy Professionals (AESP).
- Elected to the AESP Board of Directors in 2004 and re-elected in 2006, and currently serving on the AESP Executive Committee as Vice President.
- Elected to two terms as the Vice Chair of the Peak Load Management Alliance (2002-2004 and 2006 to 2008)
- Editor of the inaugural issue of the *Energy Services Journal*, Lawrence Erlbaum publishers, 1995
- Member of the National Commission on Air Quality Benefits Estimation Panel
- Member of the editorial board of *Evaluation Exchange*
- Awarded *Highest Distinction* on both PhD Comprehensive Field Exams, University of Colorado
- Recipient of University of Colorado Regents Fellowship
- Graduated *summa cum laude*, Arizona State University, 1973
- Male Scholar of the Year, Arizona State University, 1973
- Athlete/Scholar Award, Western Athletic Conference (WAC), 1972



Review of Draft DSM Guidelines for Natural Gas Distributors

IndEco

Review of the Draft DSM Guidelines for Natural Gas Distributors (EB-2008-0364)

IndEco

This document was prepared for Enbridge Gas Distribution by IndEco Strategic Consulting Inc.

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Contents

1 Introduction 1

1.1 About IndEco 2

2 Issues identified with the Draft Guidelines 3

2.1 General issues 3
2.2 TRC Calculation (section 2.1) 4
2.3 Spillover (section 2.5.3) 4
2.4 Persistence (section 2.5.4) 6
2.5 Pilot programs (section 2.7) 7
2.6 Adjustments to the approved plan (section 3.3) 8
2.7 Shared savings mechanism for resource acquisition programs (section 5.1.1) 9
2.8 Updated input assumptions (section 6.3) 11
2.9 Independent third party review (section 6.5) 13
2.10 DSM consultative (section 7.0) 14
2.11 Annual reporting guidelines (section 9.0) 15
2.12 Filing guidelines (section 10.0) 15

3 Recommended revisions 17

Appendix A. Curriculum Vitae 21

1 Introduction

This report provides a review and analysis of the Draft Demand Side Management Guidelines for Natural Gas Distributors (EB-2008-0346) (Draft Guidelines) prepared by the Ontario Energy Board Staff (Board Staff). This report also provides recommendations which balance regulatory oversight and harmonization of the guidelines governing gas Demand Side Management (DSM) and electric Conservation and Demand Management (CDM), with how the Draft Guidelines should be modified to enhance the opportunity for the natural gas distributors to achieve gas savings/TRC from their DSM activities.

This report was prepared by IndEco Strategic Consulting (IndEco) at the request of Enbridge Gas Distribution (Enbridge). To prepare this report IndEco was asked to compare the Draft Guidelines to the following:

- The Generic Decision on Natural Gas Demand Side Management (EB-2006-0021) (Generic Decision) and current practices in natural gas DSM

- The Guidelines for Electricity Distributor Conservation and Demand Management (EB-2008-0037) (Electricity Guidelines) and current practices in electricity conservation and demand management (CDM)

Based on this comparison IndEco was also asked to identify issues with the Draft Guidelines and to make recommendations for improvement. IndEco conducted this work and identified recommendations to meet the following objectives:

- Maximize the gas savings/TRC achieved from the implementation of DSM by the natural gas distributors

- Recognize the maturity of the natural gas distributors in delivering DSM and the maturity of the DSM market in Ontario

- Harmonize the Draft Guidelines and the Electricity Guidelines where appropriate

- Set clear and transparent rules for DSM that allow the gas distributors the flexibility to deliver successful DSM

- Strike the right balance of regulatory oversight for natural gas DSM in Ontario to achieve the above objectives.

1.1 About IndEco

IndEco Strategic Consulting was established in 1994. IndEco is an Ontario-based and Ontario-owned boutique energy firm, focusing on management consulting in conservation (DSM/CDM), energy efficiency, demand response, renewable energy, sustainable development and climate change. IndEco offers services in policy and framework design, strategic planning, program planning, development and delivery, stakeholder consultation, monitoring, evaluation and reporting, marketing and promotion, and awareness and training.

IndEco is a recognized expert in demand side management in Ontario, with extensive experience in both gas demand side management (DSM) and electricity conservation and demand management (CDM). Regarding DSM, IndEco has worked with both Enbridge Gas Distribution and Union Gas. We have provided advice on DSM frameworks, expert testimony at Ontario Energy Board hearings, program and policy design and program review and evaluation. Regarding CDM, IndEco has experience in program design and delivery, CDM framework development, providing expert testimony on CDM plans before the OEB, program development, program delivery, program evaluation and reporting. IndEco has also worked with over 30 distributors on CDM plans, regulatory reporting on CDM, and program delivery.

The principle authors of this report are Judy Simon, David Heeney and ««GreetingLine»». Appendix A contains the Curriculum Vitae for each author.

2 Issues identified with the Draft Guidelines

This chapter provides a description of the issues that IndEco identified in the Draft Guidelines. To identify potential issues with the Draft Guidelines IndEco compared the Draft Guidelines to the following:

- The Generic Decision and current practices in natural gas DSM
- The Electricity Guidelines and current practices in electricity CDM.

IndEco characterized the issues to be either:

- Framework items that are part of the Generic Decision or part of current practice in natural gas DSM, but not part of the Draft Guidelines; or
- Framework items that have been placed in the Draft Guidelines inappropriately as a result of harmonization with the Electricity Guidelines or with current practice in electricity CDM.

The report presents the issues in the order they appear in the Draft Guidelines, with general issues with the Guidelines presented first.

2.1 General issues

The elements contained and the wording used in the Draft Guidelines appear to reflect an attempt to take content of the Electricity Guidelines and make adjustment to it to address the gas distribution sector. While this approach works in some cases, the overall document had "an electricity distributor feel" rather than "a gas distributor feel". In an attempt to achieve harmonization between the gas and electricity distributors, the Draft Guidelines harmonized certain matters effectively. However, there were matters that should not have been harmonized and opportunities for harmonization that would have enhanced the gas DSM regulatory framework that were missed. This report focuses on the treatment of matters that should be improved and these are discussed later in this chapter.

There is a lack of clarity and consistency in the terminology used in the Draft Guidelines. This should be addressed in the final Guidelines. For example, in section 6.1 referring to the Evaluation Plan it is not clear if the "application for funding for any program(s)" is the DSM plan, referred to throughout the document. In addition in section 10.1 - Filing Guidelines a different term, "Program funding through distribution rates", is used to refer to the DSM plan. As well, there is confusion regarding the required content of the DSM plan. Traditionally, the gas distributors have addressed budgets and evaluation in the DSM plan filed with the Board and this approach has worked well. The Draft Guidelines are not clear on whether the Evaluation Plan is to become a document separate from the DSM plan. This lack of clarity is exemplified in section 6.1 by the following: "Utilities should file an Evaluation Plan along with the application for funding for any program(s). Approval of the distributor's DSM plan will be conditional upon approval of an acceptable Evaluation Plan for the program(s) contained in the DSM plan." (page 29)

Recommendation #1	**The Draft Guidelines should be revised to make it a gas distributor centric document**

Recommendation #2	**The Draft Guidelines should be revised to make them clearer and to make the terminology used in the document more consistent**

2.2 *TRC Calculation (section 2.1)*

In the Draft Guidelines it states: "If the NPV_{TRC} is positive, or the benefit to cost ratio exceeds 1, indicating that benefits exceed costs, the measure, program or portfolio is considered cost effective from a societal perspective" (Draft Guidelines, section 2.1, page 7).

The gas distributors already have an incentive to maximize TRC benefits at the portfolio level to attain the best possible SSM. Therefore the distributors are encouraged only to include programs that have a benefit to cost ratio of less than 1 in their portfolios for good reason, for example, for low-income or other hard to reach customer programs, or pilot programs. In addition, despite including programs with benefit cost ratios of less than 1 the overall portfolio TRC still must be greater than one.

Recommendation #3	**The requirement for the benefit cost ratio of > 1 should only apply to the portfolio level and therefore the requirement to have a benefit cost ratio of > 1 for measures and programs should be deleted**

2.3 *Spillover (section 2.5.3)*

The Draft Guidelines state that: "A distributor that wishes the Board to consider spillover will need to provide comprehensive and convincing evidence that clearly quantifies the effect that spillover has had on program savings and the distributor's revenue." (Draft Guidelines, section

2.5.3, page 17). There is no corresponding requirement for free riders in the Guidelines. (Draft Guidelines, section 2.5.1, page 15-16)

According to the National Action Plan for Energy Efficiency paper *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers*[1], spillover is the opposite of the free rider effect: customers that adopt efficiency measures because they are influenced by program-related information and marketing efforts, though they do not actually participate in the program. Like free-ridership, spillover is a benefit side adjustment factor in determining the net to gross ratio; free-riders deducts energy savings that would have been achieved without the efficiency program, while spillover increases savings for any effects that occurs as an indirect result of the program.

Historically, gas distributors in Ontario have taken a conservative approach to calculating TRC by focusing on net to gross ratio inputs[2] – free rider rates – that reduce the amount of savings attributable to DSM programs. With the maturity of the Ontario gas DSM market and the extensive monitoring and evaluation of DSM programs that takes place, it is appropriate for the distributors to begin to measure spillover as well as free riders as a result of their DSM programs when calculating net to gross ratios for the TRC.

Calculating spillover effects as part of calculating a net to gross ratio for the TRC is a common practice in the United States. Other gas distributors in Canada are beginning to become more interested in spillover. For example, SaskEnergy attempted to capture the spillover effect for their Commercial Boiler Program by including questions on a customer survey and by conducting informal discussions with measure suppliers.

Since free riders and spillover are adjustments to the benefit cost ratio that are two sides of the same coin – they are the same type of adjustment but in the opposite direction, one has a positive impact on TRC and the other has a negative impact, they should be treated in the same fashion as the other adjustment factors. The input assumptions to be used for the calculation of adjustment factors is being determined by the Board as part of this proceeding and comments are due on March

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[1] National Action Plan for Energy Efficiency (2008). *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers*[1]. Energy and Environmental Economics, Inc. and Regulatory Assistance Project.

[2] The net to gross ratio adjusts the cost-effectiveness so that it only includes the energy savings that result from the particular energy efficiency program. Gross energy impacts are the savings that result directly from a program. Net energy impacts reduce the gross savings by deducting free riders, deducting savings that are not achieved on site compared to forecast savings and the addition of spillover effects.

6th. It is expected that the Board will approve these assumptions prior to the filing of the multi-year plans.

If the Board is contemplating a more stringent evidentiary basis for spillover, as the Draft Guidelines are recommending, this is a significant change from practice, which has not been thoroughly treated in a more formal regulatory proceeding. Until such time as the Board holds such a proceeding and determines what, if any, new standard of evidence is required for spillover, the standard of evidence required should be the same as for free riders. Therefore, the Draft Guidelines should be amended to eliminate the more stringent requirement for spillover evidence discussed above.

Recommendation #4	**The requirement "to provide comprehensive and convincing evidence that clearly quantifies the effect that spillover has had on program savings and the distributor's revenue" should be eliminated. The standard of evidence should be the same for both spillover and free riders and this standard should be determined at the DSM proceeding**

2.4 Persistence (section 2.5.4)

Board Staff states in the Draft Guidelines: "there is a need for more thorough consideration of long-term retention, technical degradation, and persistence of savings in particular for programs with significant budgets and savings. Distributors will be expected to address persistence of savings in their next generation DSM plans and evaluations of programs". (Draft Guidelines, section 2.5.4, page 17). There is no corresponding requirement for the consideration of long-term retention, technical degradation and persistence of savings in the Electricity Guidelines. Electricity distributors are only required to "account for persistence of a CDM measure in accordance with the inputs and assumptions posted on the Board's website (Electricity Guidelines, section 3.4.3, page 15). The Board's Inputs and Assumptions for Calculating Total Resource Cost Test March 28, 2008, state that "...distributors should assume 100% persistence in assessing CDM cost effectiveness unless otherwise updated by the Board. While persistence is not likely 100%, for practicality, it is necessary to make some simplifying assumptions" (page 1).

Persistence, like free riders and spillover, is a standard adjustment factor in calculating net to gross ratios for the TRC. Ontario gas distributors have been including persistence of DSM measures in the TRC calculation for many years. Persistence should be treated in the same way as all the other adjustment factors that the gas distributors are expected to calculate for the TRC. Therefore, the more stringent requirements for calculating persistence in the Draft Guidelines should be eliminated. This would still continue the more stringent requirement for calculating persistence for natural gas DSM as compared to CDM reflecting the maturity of gas DSM as compared to CDM, but it would be consistent with the calculation of the other adjustment factors for gas TRC, as proposed earlier in this report. If the Board believes that the distributors need to prepare particular studies related to the calculation of persistence for the next round of multi-year DSM plans, this should be determined based on the multi-year plans and related evidence presented by the distributors and the intervenors.

Recommendation #5	**The requirement for "a more thorough consideration of long-term retention, technical degradation, and persistence of savings in particular for programs with significant budgets and savings", should be eliminated. If the Board believes that the gas distributors need to prepare particular studies related to the calculation of persistence for the next round of multi-year DSM plans, this should be determined based on the multi-year plans and related evidence presented by the distributors and the intervenors**

2.5 Pilot programs (section 2.7)

In the Draft Guidelines the Board employs a very narrow definition of a pilot program stating "A pilot program is one that involves the installation, testing or evaluation of technologies that are not already in use in Ontario, or in limited use, and that serves as a tentative model for future development". (Draft Guidelines, section 2.7, page 18) This definition suggests that pilot programs are only those programs that employ a new technology.

In other jurisdictions, and in Ontario currently, gas DSM programs and CDM programs that are being piloted or tested do not have to include a new technology. Instead they may involve a new way of packaging or bundling existing technologies or a new method of program delivery. For example, the Energy Efficiency Assistance Program for Houses Program was considered a pilot by the OPA even though it only provided standard energy efficient measures e.g. compact fluorescent bulbs, low-flow showerheads, indoor clotheslines, water heater blankets and hot water pipe insulation, and programmable thermostats to low-income households. What made the program a pilot was that these technologies were combined with an energy audit, education and outreach, and monitoring and verification of energy savings in such a way to produce a new program that required testing.

A pilot program may also be one not offered to all customers, or that would otherwise restrict the number of participants as part of a 'test'. As such, will necessarily not have the economies of scale associated with a broader roll-out.

To take into account these types of programs the definition of pilot program should be expanded in the Draft Guidelines to include those programs that make use of existing technologies in a new and innovative way as well as the installation, testing or evaluation of new technologies.

Pilot programs should be considered 'tests' or research into the viability of programs. Such a treatment of pilot programs will provide an incentive to gas distributors to be more innovative regarding program design and delivery, to pursue next generation DSM programs and to achieve greater savings over the long term. Motivating this behaviour is supportive of the provincial government's policy to create a culture of conservation. Such an approach to pilot programs also recognizes the maturity of the gas distributors in delivering DSM and the maturity of the gas DSM market. To allow for this the gas distributors should be allowed to propose a separate DSM budget in a new program area – pilot programs - distinct from resource acquisition, market transformation and low income customers.

In the Generic Decision (Issue 2.2, page 37) pilot programs were an exception to the rule that that all measures and programs should exceed a benefit to cost ratio of 1. This exception has not been included in the Draft Guidelines (section 2.1). The Board should reinstate the existing requirement from the Generic Decision that pilot programs do not need to achieve a benefit cost ratio of >1.

Recommendation #6	**The definition of pilot program in the Draft Guidelines should be expanded to include those programs that make use of existing technologies in a new and innovative way as well as the existing definition that addresses installation, testing or evaluation of new technologies**

Recommendation #7	**Gas distributors should be allowed to propose a separate DSM budget in a new program area for pilot programs**

Recommendation #8	**The Board should reinstate the existing requirement from the Generic Decision that pilot programs do not need to achieve a benefit cost ratio of >1**

2.6 Adjustments to the approved plan (section 3.3)

The requirement that "utilities should apply for approval where cumulative fund transfers among Board-approved programs that exceed

20% of the approved annual budget, as well as for approval to re-allocate funds to new programs that are not part of distributor's approved DSM plan" (Draft Guidelines, section 3.3, page 20) should be removed from the Draft Guidelines. Having this requirement removes necessary flexibility that gas distributors now have to manage programs within their DSM portfolio successfully. This flexibility enables the gas distributors to adjust to shifts in changing market conditions, which is particularly important in these quickly changing economic times. Requiring the gas distributors to seek approval for fund transfers above 20% will reduce program effectiveness. Even with relatively quick approvals which the Board has been able to provide to the electricity distributors, this added provision will likely cause significant DSM program delays and loss of savings/TRC as programs ramp down, then stop and then ramp up again.

Unlike for CDM[3], this requirement was never imposed for gas DSM. This budget flexibility restriction was not found to be necessary at the inception of gas DSM with E.B.O. 169-III or in the Generic Decision. With more than 10 years of experience in gas DSM (and Enbridge since 1995), the gas distributors have proven themselves to be responsible in reallocating dollars in their DSM budgets to maximize savings/TRC. As a result, other than harmonization with current practice on the electricity side, which in this case would place an unnecessary restriction on gas DSM, there is no reason to impose this new requirement on the gas distributors.

Recommendation #9	**The requirement that "utilities should apply for approval where cumulative fund transfers among Board-approved programs that exceed 20% of the approved annual budget, as well as for approval to re-allocate funds to new programs that are not part of distributor's approved DSM plan", should be eliminated**

2.7 Shared savings mechanism for resource acquisition programs (section 5.1.1)

The Draft Guidelines state that the reward structure for DSM will continue to be calculated as a non-linear function relative to TRC savings

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[3] This "20% rule" is part of the approval requirement for the third tranche CDM plans produced by the electricity distributors beginning in 2005. Rather than requiring that the CDM plans be comprised of particular programs, as in the case of natural gas DSM plans, the Board permitted the electric distributors to divide their CDM budget into buckets or categories. The "20% rule" allowed the Board the opportunity to review and approve how the money was actually being spent in cases where there was more than a 20% change to a particular bucket or category of spending.

as decided in the DSM generic proceeding. However, the Electricity Guidelines specify the particular function for calculating the SSM is 5% of the net benefits (pre-tax) created by the approved CDM portfolio (Electricity Guidelines section 6.2, page 20).

The incentive offered to the gas and electric distributors should be harmonized so that both are able to recover 5% of net benefits as a reward for conducting DSM/CDM to make it equally motivating for a distributor, either gas or electricity, to carry out a particular resource acquisition program by receiving the same reward for performance.

This harmonization should occur so that in the case of both CDM and DSM, it is clear that the distributor is delivering a service, every unit of which is equally beneficial to society, and therefore the distributor is rewarded equally for each TRC unit achieved. Since there is no government policy in place that indicates that a dollar of gas TRC is less valuable to society than a dollar of electricity TRC, the two types of resource acquisition programs should be equally encouraged and therefore, equally compensated.

If the incentive is harmonized, it will also help to smooth regulatory approvals for DSM. This will occur as a consequence of harmonizing the SSM which will result in the removal of the requirement for the gas distributors to set savings targets (which currently exists under the non-linear function), as every TRC unit achieved will be worth the same. The removal of the target requirement will streamline the DSM regulatory approvals process by removing a significant area of ongoing contention between distributors and their stakeholders. The removal of contention by eliminating target setting will allow stakeholders and distributors to focus more of their attention on program design, delivery and evaluation.

The Demand Side Management Variance Account (DSMVA) has traditionally been provided to allow the gas distributors to continue DSM programs that were more successful than anticipated. Since setting targets is not required to have meaningful DSM results and incentives for the gas distributors, this suggests the need for a change to the DSMVA (Draft Guidelines, section 8.4, page 39). Rather than it being used to help the distributor to achieve savings beyond the target, the DSMVA should be limited to additional program incremental costs beyond the program budget to achieve more savings, up to a percentage of the distributor's total DSM budget for the year.

Recommendation #10	**The requirement that "the reward structure for DSM is to be calculated as a non-linear function relative to TRC savings", should be replaced with "the reward structure for DSM should be the same as that for the electric distributors, that being 5% of the net benefits (pre-tax) created by the approved CDM portfolio". The Board should replace "the requirement for the DSMVA to be used to help the distributor to achieve savings beyond the target up to 15% of the distributor's total DSM budget for the year ", with "the DSMVA should be limited to additional program incremental costs beyond the program budget to achieve more savings, up to a percentage , t o be determined on an annual basis, of the distributor's total DSM budget for the year "**

2.8 *Updated input assumptions (section 6.3)*

The Draft Guidelines state that "the input assumptions used for the calculation of LRAM, SSM and other financial incentives should be the best available at the time of the independent third party review" (Draft Guidelines, section 6.3, page 34). The rationale for this presented in the Discussion Paper accompanying the Draft Guidelines is that this will remove the need for estimating and having locked-in free riders and technology savings assumptions from the year before. Board Staff also state in this Discussion Paper that this requirement should not expose distributors to undue risk as they now have several years of experience in developing and delivering programs, and establishing targets.

The removal of the requirement to lock-in input assumptions for the calculation of the SSM places undue risk on distributors in the delivery of their DSM programs. It is not a DSM maturity issue; it is a limitation of program delivery that can occur regardless of the DSM maturity of the distributor delivering the program. While it is true that risks may be less for a program that has been delivered for many years, for new programs or where conditions change, there still may be situations for which the distributors cannot adapt. While it may be possible to make program corrections in program delivery to address certain changes in input assumptions, it will not always be practical or possible due to, for example, the resulting major increased program costs, especially where the program has required employing third party delivery agent contracts, or hiring additional staff.

The inability to adjust to changing circumstances increases as program delivery comes closer to program completion. For example, it may be easier to shift resources early on in delivery, but impossible at the beginning of the fourth quarter. The gas distributors should not be penalized for changing conditions they cannot control as long as they make best efforts to adjust, where appropriate, in response to new knowledge regarding input assumptions, and this can be demonstrated during a DSM proceeding.[4] Consistent with the requirements for electricity distributors and with the Generic Decision, the Guidelines should indicate that gas DSM input assumptions for the SSM used at the beginning of any year should be those assumptions in existence in the immediately prior year, adjusted for any changes in the audit of that prior year. (Generic Decision, page 11).

In current practice the gas distributors act on a multi-year DSM plan which has been approved by the Board. Based on this approval which sets the rules and assumptions for DSM for the term of the plan, the gas distributors pursue DSM.

In determining the assumptions for the next multi-year plan, the Board has retained external expertise and has included comment on these assumptions as part of this proceeding. If assumptions can be unlocked at any time, this provides a significant disincentive to intervenors to participate effectively in the setting of these assumptions upfront, since the assumptions can be changed at any time. To use their time wisely, intervenors are likely to focus attention on assumptions at the end of the year. This will undermine the Board's efforts to set assumptions upfront and the gas distributors' efforts to implement their programs according to the upfront assumptions, and will increase contention in the regulatory process, making the process less likely to achieve clearance of the DSM accounts.

The unlocking of the assumptions represents a fundamental change to the gas DSM framework. The benefits to DSM of setting assumptions upfront and having them remain in place for the year for the purpose of calculating the SSM has been debated at previous Board proceedings since 2002. Each time the debate has taken place, the Board has reaffirmed the need to set the assumptions upfront and have them remain in place for the year. The unlocking of these assumptions represents a major departure from gas DSM practice and should not take place until the Board has held a full hearing on the matter and is satisfied that such a fundamental change is warranted.

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[4] For example, Enbridge developed an application, which was filed with the Board, outlining requested changes to the input assumptions for its 2008 program year. The Board held a proceeding, EB-2008-0384, to review the application and approved the changes to the input assumptions proposed.

Recommendation #11	**The requirement that "the input assumptions used for the calculation of SSM and other financial incentives should be the best available at the time of the independent third party review", should be replaced with the requirement from the Generic Decision that "input assumptions for the SSM and other financial incentives used at the beginning of any year should be those assumptions in existence in the immediately prior year, adjusted for any changes in the audit of that prior year"**

2.9 Independent third party review (section 6.5)

The Draft Guidelines indicate that "Utilities should undertake program evaluations according to the approved Evaluation Plans, and have the evaluations reviewed by an independent third party engaged for the purposes of LRAM, SSM and other financial incentive claims filed with the Board." (Draft Guidelines, section, 6.5, page 35). This appears to indicate that all DSM evaluations would be subject to independent third party evaluation. This provision is not necessary and would add additional regulatory burden to the gas distributors.

In current practice and consistent with the Generic Decision (Issue. 9.3, page17) " ...a third party audit of the Evaluation Report is required". There is no additional requirement for a third party audit of all the evaluations. The Draft Guidelines appear to expand the purview of the audit to include all evaluations that the distributor or a third party carries out on behalf of the distributor. In current practice, and consistent with the Generic Decision, the audit that a distributor has conducted on a particular Evaluation Report has its own terms of reference, which are determined in consultation with stakeholders. Therefore, the purview of each audit is determined based on the type of evaluation that should take place, allowing for a focused and cost-effective approach. Requiring that the audit be done on all evaluations eliminates this opportunity for focus and may lead to the conduct of components of an audit that are not needed, thereby resulting in unnecessary cost to ratepayers. Therefore, the Draft Guidelines should be revised to make it clear that only the Evaluation Report prepared is subject to independent third party review (audit).

Recommendation #12	**The requirement that the "the evaluations must be reviewed by an independent third party engaged for the purposes of LRAM, SSM and other financial incentive claims filed with the Board", should be replaced with the "only the Evaluation Report prepared is subject to independent third party review (audit) for the purposes of LRAM, SSM and other financial incentive claims filed with the Board"**

2.10 DSM consultative (section 7.0)

The Draft Guidelines indicate that the distributors should engage and seek advice from a variety of stakeholders and experts in the development and operation of their DSM plans as they consider appropriate, and then goes on to prescribe the type of consultation (a Consultative), the minimum frequency of the meetings, being two, and what the purpose of the meetings should be.

Distributors have been engaging and seeking advice from a Consultative and an audit committee for more than a decade. Some aspects of this engagement have worked well, and have improved DSM results, while some aspects have not and have led to increased contention, regulatory burden and delays in the approval process. Given the maturity of gas utility DSM and the up-coming filing of the next round of multi-year DSM plans, rather than asking the gas distributors to develop a terms of reference for the Consultative and an audit committee, it is the opportune time for the Board to ask the gas distributors to step back from the existing consultation processes and determine how best to maximize savings/TRC, while balancing the need for effective consultation and regulatory scrutiny. Such a process has not been carried out since the Consultative and audit committee were created.

The gas distributors have a vested interest in consulting with, and seeking agreement from, their stakeholders in order to obtain a smooth approval of LRAM, SSM and other incentives. Therefore the Board should ask the distributors, as part of their multi-year filing, to propose to the Board the most cost-effective and meaningful way for the gas distributors to conduct consultation based on their extensive experience.

It is noteworthy that the Electricity Guidelines do not prescribe a consultation process for the electricity distributors, even though CDM is less mature than gas DSM and these distributors have less experience with consulting stakeholders than do the gas utilities. To take account of the experience and maturity of the two industries, gas distributors with a longer proven track record in DSM consultation, should require less oversight from stakeholders than an industry with a shorter proven track record.

To address the above issues effectively, it is recommended that the first paragraph of section 7.0 of the Draft Guideline be preserved. However, the remainder of page 36 and all of page 37 should be deleted. Section 7.0 on page 38 should be preserved.

Recommendation #13	**The requirement in the Draft Guidelines in section 7.0 that "the distributors should engage and seek advice from a variety of stakeholders and experts in the development and operation of their DSM plans as they consider appropriate", should be preserved, however, the remainder of page 36 and all of page 37 of section 7.0 should be deleted. Section 7.0 on page 38 should be preserved**

Recommendation #14	**The Board should ask the gas distributors, as part of their multi-year filing, to propose to the Board the most cost-effective and meaningful way for the gas distributors to conduct consultation on DSM**

2.11 Annual reporting guidelines (section 9.0)

The Draft Guidelines require the preparation of an Annual Report "summarizing the results of the previous year, and at the end of the plan term, addressing results for the entire plan term". The Draft Guidelines go on to prescribe the sections in the Annual Report and their required content (Draft Guidelines, section 9.0, page 40). Requiring an Annual Report is an unnecessary additional report for the gas distributors to prepare. The filing annually of the Evaluation Report, and the financial information for the SSM, LRAM and DSMVA (including the audit) is a requirement of the *Natural Gas Reporting & Record Keeping Requirements* (RRR) in Rules 2.1.12 and 2.1.5. This Evaluation Report already contains the information prescribed in the Draft Guidelines for the Annual Report. Since the material to be covered by the Annual Report is already being filed by the gas distributors pursuant to the RRR, the requirement in the Draft Guidelines to file an Annual Report should be eliminated.

Recommendation #15	**The requirement for the preparation of an Annual Report should be eliminated, thereby eliminating the need for section 9.0 of the Draft Guidelines**

2.12 Filing guidelines (section 10.0)

The Draft Guidelines harmonize the filing requirements of gas distributors with those of the electricity distributors by providing details of what should be filed to describe each program, the Evaluation Plan, the LRAM, the SSM and to make adjustments to an approved plan. This harmonization is unnecessary as the gas utilities already have the RRR and have been making filings successfully related to the above without the need for more prescriptive guidance. Including these additional filing requirements increases the time and expenditures required by the gas distributors to prepare their filings without adding any additional value. In recognition of the maturity of gas DSM and the gas utilities in successfully delivering it in compliance with Board requirements, and that there are already filing requirements prescribed in the RRR, there is no need for further prescription. Therefore, the filing guidelines in section 10.0 of the Draft Guidelines should be eliminated.

Recommendation #16	**The filing guidelines in section 10.0 of the Draft Guidelines should be removed**

3 Recommended revisions

This chapter presents a list of the recommended revisions that should be made to the Draft Guidelines based on the issues identified in the previous chapter. These recommended revisions are being made to meet the following objectives:

- Maximize the gas savings/TRC achieved from the implementation of DSM by the natural gas distributors
- Recognize the maturity of the natural gas distributors in delivering DSM and the maturity of the DSM market in Ontario
- Harmonize the Draft Guidelines and the Electricity Guidelines where appropriate
- Set clear and transparent rules for DSM that allow the gas distributors the flexibility to deliver successful DSM
- Strike the right balance of regulatory oversight for natural gas DSM in Ontario to achieve the above objectives.

The recommendations are presented below in the order that they appear in the Draft Guidelines except in regard to the DSMVA:

1. The Draft Guidelines should be revised to make it a gas distributor centric document
2. The Draft Guidelines should be revised to make them clearer and to make the terminology used in the document more consistent
3. The requirement for the benefit cost ratio of > 1 should only apply to the portfolio level and therefore the requirement to have a benefit cost ratio of > 1 for measures and programs should be deleted
4. The requirement "to provide comprehensive and convincing evidence that clearly quantifies the effect that spillover has had on program savings and the distributor's revenue" should be eliminated. The standard of evidence should be the same for both spillover and free riders and this standard should be determined at the DSM proceeding

5. The requirement for "a more thorough consideration of long-term retention, technical degradation, and persistence of savings in particular for programs with significant budgets and savings", should be eliminated. If the Board believes that the gas distributors need to prepare particular studies related to the calculation of persistence for the next round of multi-year DSM plans, this should be determined based on the multi-year plans and related evidence presented by the distributors and the intervenors

6. The definition of pilot program in the Draft Guidelines should be expanded to include those programs that make use of existing technologies in a new and innovative way as well as the existing definition that addresses installation, testing or evaluation of new technologies

7. Gas distributors should be allowed to propose a separate DSM budget in a new program area for pilot programs

8. The Board should reinstate the existing requirement from the Generic Decision that pilot programs do not need to achieve a benefit cost ratio of >1

9. The requirement that "utilities should apply for approval where cumulative fund transfers among Board-approved programs that exceed 20% of the approved annual budget, as well as for approval to re-allocate funds to new programs that are not part of distributor's approved DSM plan", should be eliminated

10. The requirement that "the reward structure for DSM is to be calculated as a non-linear function relative to TRC savings", should be replaced with "the reward structure for DSM should be the same as that for the electric distributors, that being 5% of the net benefits (pre-tax) created by the approved CDM portfolio". The Board should replace "the requirement for the DSMVA to be used to help the distributor to achieve savings beyond the target up to 15% of the distributor's total DSM budget for the year ", with "the DSMVA should be limited to additional program incremental costs beyond the program budget to achieve more savings, up to a percentage , t o be determined on an annual basis, of the distributor's total DSM budget for the year "

11. The requirement that "the input assumptions used for the calculation of SSM and other financial incentives should be the best available at the time of the independent third party review", should be replaced with the requirement from the Generic Decision that "input assumptions for the SSM and other financial

incentives used at the beginning of any year should be those assumptions in existence in the immediately prior year, adjusted for any changes in the audit of that prior year"

12. The requirement that the "the evaluations must be reviewed by an independent third party engaged for the purposes of LRAM, SSM and other financial incentive claims filed with the Board", should be replaced with the "only the Evaluation Report prepared is subject to independent third party review (audit) for the purposes of LRAM, SSM and other financial incentive claims filed with the Board"

13. The requirement in the Draft Guidelines in section 7.0 that "the distributors should engage and seek advice from a variety of stakeholders and experts in the development and operation of their DSM plans as they consider appropriate", should be preserved, however, the remainder of page 36 and all of page 37 of section 7.0 should be deleted. Section 7.0 on page 38 should be preserved

14. The Board should ask the gas distributors, as part of their multi-year filing, to propose to the Board the most cost-effective and meaningful way for the gas distributors to conduct consultation on DSM

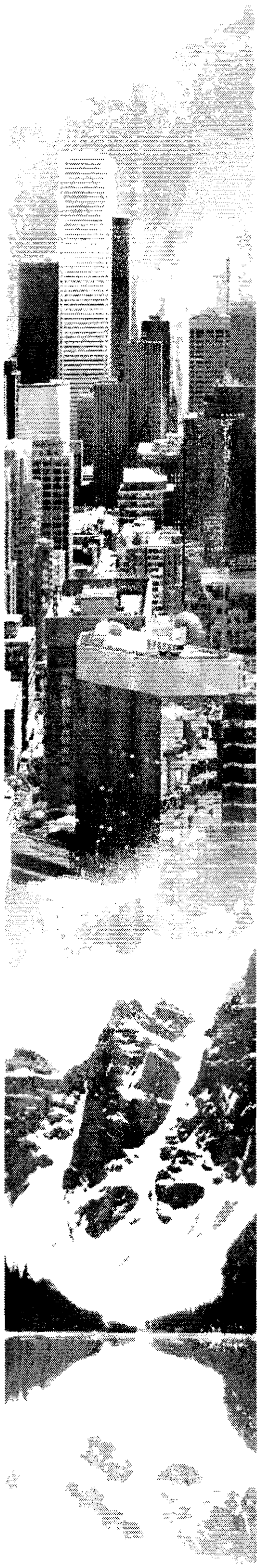
15. The requirement for the preparation of an Annual Report should be eliminated, thereby eliminating the need for section 9.0 of the Draft Guidelines

16. The filing guidelines in section 10.0 of the Draft Guidelines should be removed

Appendix A. Curriculum Vitae

- Judy Simon
- David Heeney
- Shona Adamson

IndEco



Judy Simon

Vice President

Judy Simon, Vice President, is an environmental scientist and strategic planner with over 25 years experience in energy and environmental issues, focusing on energy regulation, energy efficiency and conservation, renewables, and climate change. Judy has extensive experience in both the public and private sector and has been a management consultant in the energy field for 20 years.

Judy was a part-time Board member of the Ontario Energy Board between 1992 and 2002, giving her extensive knowledge and experience in the development and implementation of natural gas and electricity regulatory frameworks in Ontario. Judy was appointed as the Board's leading expert on DSM, and on environmental matters related to energy regulation, and served in that capacity for ten years.

Expertise

- Strategic planning
- DSM/CDM, distributed energy, and renewable energy policy analysis, program development and implementation
- Program monitoring, evaluation and reporting
- Energy adjudication
- Electricity and natural gas markets and energy regulation in Ontario
- Stakeholder, engagement, social marketing and training

Employment History

- Vice President, IndEco (1994 - present)
- President, Judy Simon + Associates (1989 – present)
- Part-time Board Member, Ontario Energy Board (1992- 2002)
- Manager, Technology Policy, Ontario Ministry of Industry, Trade and Technology (1987-1989)
- Manager, Environmental Assessment Branch, Ontario Ministry of Environment (MOE) (1982-1987)
- Environmental Planner, Environmental Assessment Branch, MOE (1981-1982)
- Energy Planner, Conservation and Renewable Energy Group, Ontario Ministry of Energy (1980-1981)
- Energy Researcher, Algas Resources, Trans Canada Pipelines (1978)

PROFESSIONAL QUALIFICATIONS

Master of Environmental Design (Environmental Science), University of Calgary (1980)

Bachelor of Science, University Scholar, Great Distinction, McGill University (1977)

APPEARANCES

1985	Joint Board, Ontario Hydro Southwestern Ontario Transmission System Expansion Program. On behalf of the Ontario Ministry of the Environment regarding Ministry environmental policy and approvals
2003	Ontario Energy Board, on behalf of Enbridge Gas Distribution Inc. regarding their DSM framework and incentive mechanisms
2004	Ontario Energy Board, on behalf of Brantford Power regarding the approval of its 2005 CDM Plan
2004	Ontario Energy Board, on behalf of Milton Hydro regarding the approval of its 2005 CDM Plan
2005	Ontario Energy Board, on behalf of Low-Income Energy Network regarding CDM policies and programs, regulated price plan and other matters
2008	Ontario Energy Board, on behalf of GLOBE regarding the OEB low income policy proceeding

ADVISORY COMMITTEES AND BOARDS

April 2008 to present	Member, Toronto Atmospheric Fund Grants and Special Projects Committee
Jan. 2006 to present	Member, Board of Directors, Clean Air Partnership
Jan. 2005 to July 2006	Member, City of Toronto's Environment Roundtable
Oct. 2002 to March 2006	Member, Grants and Loans Committee, Toronto Atmospheric Fund
Apr. 1999 to 2002	Vice President, Environment, Provincial Council of Women
Dec.1996 to Mar. 2008	President of the Board of Directors, Canadian Environmental Law Association (CELA)
Apr. 1994 to Mar. 2008	Member of the Board of Directors, CELA

May 1992 to May 2002	Part-time Board member of the Ontario Energy Board
Sept. 1990 – Dec. 2001	Member, Environmental Advisory Panel to the President, Ontario Hydro

AWARDS

1981	Commendation from Mayor, City of Toronto, for work on Toronto Recycling Action Committee
1997-1980	Natural Sciences and Engineering Post-graduate Scholarship
1972-1977	McGill University Scholarship
1972 -1977	Steinberg Canada Scholarship

SELECTED PROJECTS

Strategic/business planning

- Windstream Inc.. Provision of advice and preparation of a submission to the Ontario Energy Board (OEB) on behalf of Windstream, dealing with issues facing electricity transmitters and wind generators. Project manager.

- Northwatch. Provision of advice and preparation of brief for OEB proceeding on generation connections taking into account special needs/situation of northern Ontarians including aboriginals and off-grid residents. Project manager.

- Conservation Bureau. Provision of business planning and strategic advice. This included guidance on the creation and implementation of internal policy and administrative structures, and the identification of staffing and budgeting requirements for the planning, coordination and reporting function. It also included completion of the LDC, government and other market player scorecard components of the Chief Energy Conservation Officer's 2006 Annual Report. Wrote sections dealing with the natural gas utilities and non-Ontario Power Authority conservation and demand management by the electric utilities for the 2007 and 2008 Annual Reports. Project manager.

- Ontario Power Authority. Assisting the OPA to design and launch the $400M program for LDC CDM including establishing the rules for funding, the application process and the contract elements, and development of program templates and detailed program designs for the OPA's Standard LDC programs (Programs in a Box). Work is ongoing and being completed in partnership with Navigant. Project manager.

- Guelph Hydro. Development of a CDM business plan using IndEco's strategic planning process to develop priorities for the plan, and strategies to realize the priorities. Project manager.

- Energy Efficiency Office, City of Toronto. Development of the Report on the Development of the Energy Plan for Toronto. Senior advisor.

- Low-income Energy Network. Preparation of submissions on Regulated Price Plan and low-income consumers to the OEB and prepared with FRC Canada. Project manager.

- Canadian Energy Efficiency Alliance. Preparation of strategy papers on CDM which were submitted to the OEB and to the Minister of Energy. Project manager. Served as DSM expert to Alliance's DSM policy committee.

- Toronto Hydro and Milton Hydro. Development of business case that helped both utilities to decide to go forward to develop a DSM plan for 2003. Project manager.

- Energy Efficiency Office, City of Toronto. Senior policy advisor on the identification and evaluation of opportunities for strengthening partnerships with Toronto Hydro through joint work on DSM.

- Energy Efficiency Office, City of Toronto. Senior policy advisor on the development of a Sustainable Energy Business Plan for the Energy Efficiency Office for 2002.

- City of Toronto. Development of the City of Toronto's Implementation Plan for the Environmental Plan. Project manager.

- Brewers of Ontario. Development and implementation of a business strategy for enhancement and recognition of environmental performance in packaging. Project manager.

- Brewers of Ontario. Development of environmental strategy including opportunities to reduce energy use and emissions in new facilities and vehicles. Project manager.

DSM/CDM planning, program development, implementation, monitoring and evaluation

- Hydro One. Delivery of 2008 Power Savings Blitz. Work is ongoing. Account executive.

- Barrie Hydro. Delivery of 2007 and 2008 ERIP. Delivery of marketing and promotion related to 2008 GRRR, peakSaver, Summer Savings. Delivery of 2008 Power Savings Blitz. Work is ongoing. Account executive.

- OPA. Evaluation of Veridian and PowerStream Neighbourhood **peaksaver** custom programs. Work is ongoing. Senior advisor.

- Peterborough Distribution Inc. Delivery of 2007 ERIP and project management for Summer Savings, peakSaver, and GRRR.

- UHN. Design and delivery of 3-year (2007-09) comprehensive energy management program including social marketing, employee engagement, operator training, audit and retrofits. Work is ongoing. Senior advisor.

- NEPA Group. Delivery of 2007 ERIP. Project manager.

- Guidance on the preparation of workplans and budgets for applications to the OPA LDC CDM fund. Project manager.

- Oakville Hydro. Provide guidance on the preparation of workplans and budgets for applications to the OPA LDC CDM fund. Project manager.

- Kitchener-Wilmot Hydro, Waterloo North Hydro and Cambridge North Dumfries Hydro. Assist in the preparation of application to the OPA for funding for the delivery of LDC standard programs. Project manager.

- Oakville Hydro. Preparation of OEB application to exceed 20% rule for CDM spending. Project manager.

- Enbridge Gas Distribution. Advice on DSM policies, regulatory treatment of DSM, low-income programs and other matters in the 2006 generic gas DSM hearing and on Enbridge's 3-year DSM plan. Project manager.

- Toronto Atmospheric Fund. Development of a municipal lighting program design for Toronto Atmospheric Fund. Work involved review of energy forecasts and needs in the GTA, survey of existing municipal and LDC lighting programs in the GTA, evaluation of measures (including TRC calculations), and preparation of written descriptions. Project manager.

- Burlington Hydro. Management of key aspects of the implementation of the 2005-2007 CDM plan including development of detailed program designs, implementation plans marketing and advertising programs, as well as monitoring and evaluation systems for the utility's lighting retrofit programs for its general service customers, municipal customers, and for its residential new construction program. Project manager.

- Milton Hydro. Policy advisor on Milton Hydro CDM portfolio for 2005 and for 2006.

- Senior regulatory advisor on the development of post-third tranche 2006 CDM plans for Burlington Hydro and Milton Hydro.

- Enbridge Gas Distribution. Advice on improvements to its DSM regulatory framework including budget and target setting, its incentive, stakeholder input, monitoring, evaluation and reporting with Navigant. Project manager.

- Toronto Hydro. Investigation of options for Toronto Hydro to reduce customer bills including an illustrative approach for 2003 to DSM with Fraser & Company. Project manager.

- Canadian Energy Efficiency Alliance. Co-author of paper, "The Consumer Benefits of Interval Metering, with Marion Fraser, Fraser & Company. Project manager.

- Ontario Energy Board. As Board member, a principal author of natural gas regulatory framework for DSM (E.B.O. 169-III); adjudicator in over 100 cases.

Hard to reach consumers DSM/CDM

- GLOBE. Provision of strategic advice on programs and policies for social housing to be tabled at OEB low income proceeding. Work is ongoing. Project manager.

- Northwatch. Provision of strategic advice on CDM and renewables component of IPSP taking into account special needs of northern Ontarians, including aboriginals and off-grid residents. Project manager.

- Enbridge Gas Distribution. Benchmarking of customer care programs, including those for seniors and hardship customers compared with other Canadian and US utilities and jurisdictions. Made recommendations on improvements to programs and linkages to DSM programs. Project manager.

- Ontario Power Authority. Development of conservation program concepts for social housing, low-income tenants in private buildings, and low-income homeowners. Project manager.

- Low-Income Energy Network. Represented LIEN on the Union Gas DSM Consultative. Project manager.

- Brantford Power. Development of Conserving Homes program, the award winning Canadian low-income CDM program. Project manager.

- Low-Income Energy Network. Prepared evidence and argument that included the recommended design for Union Gas' low-income program, which was approved by the OEB in Union Gas' 2006 DSM proceeding (EB-2005-0507). Project manager.

- Low-Income Energy Network. Prepared evidence and argument that involved policies and program designs for low-income CDM in EB-2005-0523. Project manager.

- Low-Income Energy Network. Fundraising through a Trillium proposal to secure funds and then to use the funds to create the LIEN website and to hold the first annual conference on low-income energy matters with LIEN members and other interested NGO's, government and other participants. Project manager.

- Low-Income Energy Network. Development of a low-income energy efficiency program template for electric LDC's to adopt for low-income homeowners and tenants who pay their electricity bills directly. Work was funded by Ministry of Energy and Toronto Atmospheric Fund. Project manager.

- Toronto Environmental Alliance. Development of low-income energy conservation and assistance strategy for Ontario. Funded by Toronto Environmental Alliance and Ministry of Energy. Project manager.

- Canadian Environmental Law Association. Preparation of a CDM policy paper on the appropriate framework for CDM in Ontario to best meet the needs of low-income consumers which was submitted to the OEB as part of the consultation related to the Minister's Directive to the OEB on CDM. Project manager.

DSM/CDM best practices

- Canadian Gas Association. Identification of DSM best practices for monitoring and evaluation in Canadian gas utilities. Related paper presented at AESP, January 2009. Project manager.

- EDA. Presentation on comparison of CDM in US jurisdictions and in Ontario and Ontario at EnerCom 2007. Project manager.

- Association of Energy Service Professionals. Publication of paper and delivery of presentation on DSM Best Practices in the Canadian Natural Industry, winter 2007 and at AESP, January 2007.

- Electricity Distributors Association. Preparation and delivery presentation on CDM best practices in gas and electric LDCs to EDIST Conference with Enbridge Gas Distribution, winter 2006. Project manager.

- Canadian Gas Association. Preparation of policy paper on declining average across gas utilities in Canada and recommendations on treatment in rates. Project manager.

- Conference Board of Canada. Author of discussion paper on successful natural gas regulatory DSM frameworks in Canada, published in November 2005.

- Canadian Energy Efficiency Alliance. Senior advisor on Webinar on best practices with Enbridge Gas Distribution.

- Canadian Gas Association. Identification of natural gas DSM best practices among natural gas utilities across Canada with Bruce Vernon & Associates. Senior policy advisor.

- Enbridge Gas Distribution. Identification of best practices regarding incentive mechanisms in North American Gas utilities with Navigant. Project manager.

- Enbridge Gas Distribution. Survey of natural gas DSM in North American jurisdictions with Navigant. Project manager.

Training

- Conservation and demand management training for Ontario's local distribution utilities. The development and delivery of IndEco's training program for new electric utility staff and a refresher for more experienced staff on conservation and demand management. The course includes training in program design, delivery, management, monitoring and evaluation, regulatory approvals and reporting. Federal and provincial programs and US program examples are presented. Account executive and trainer.

- Canadian Electricity Association. Facilitator for joint CEA-Natural Resources Canada workshop on monitoring and evaluation of conservation and demand management programs. Work included providing a workshop report, summarizing workshop content - issues, lessons learned. Project manager and facilitator.

- Canadian Gas Association. Design and delivery of a workshop on monitoring and evaluation of energy efficiency and conservation programs. Work also included the preparation of a report on issues and lessons learned from this workshop and 3 previous ones. Project manager and facilitator.

- Clean Air Partnership. Conservation and demand management training for municipal officials. On behalf of the Clean Air Partnership, IndEco designed and delivered a training program for municipal staff targeted at southern Ontario municipalities (members of GTA-Clean Air Council) on conservation, energy efficiency and demand response. Account executive and trainer.

- Milton Hydro. Design and implementation of a breakfast seminar series with the utility's GS customers on DR. Senior advisor.

- Burlington Hydro. Design of training workshops for the ICI sector and local Burlington builders on energy efficiency and the DSM programs available to them. Senior advisor.

- City of Ottawa and Canadian Gas Association. Design and delivery of workshop to local builders, architects, engineers, utilities, energy managers and consultants on conservation and renewable energy opportunities in Ottawa to improve air quality and reduce GHGs. Project manager.

- City of Mississauga and Canadian Gas Association. Design and delivery of workshop to builders, architects, engineers, utilities, energy managers and consultants on conservation and renewable energy opportunities in Mississauga to improve air quality and reduce GHGs. Project manager.

- Canada Mortgage and Housing Corporation. Development and implementation of design charette for multi-residential and commercial buildings, which became a key basis for CMHC to offer these charettes with Sustainable Buildings Canada across the country. Project manager.

- Association of Canadian Distillers. Design and delivery of a training and awareness program on energy efficiency opportunities in whiskey manufacturing plants to manufacturer members.

Stakeholder engagement and social marketing

- York Region. Delivery of water conservation programs for York Region (2009-2011) including a rain barrel program, rebates for water saving toilets and washing machines, and a pre-rinse spray valve program in cooperation with Enbridge Gas Distribution and ICI water audits. With Finn Projects. Senior advisor.

- University Health Network. Design and delivery of a social marketing and employee engagement program for energy efficiency and energy conservation in Toronto Western and Toronto General Hospitals (2008-2010). Senior advisor.

- Ontario Power Authority. Design and delivery of the stakeholder consultation process for the $400M CDM program including the design and delivery of the Program Design Advisory Group and Program Operations Design Group activities. With Navigant Consulting. Project Manager.

- Toronto Catholic District School Board. Design and implementation of the Energy Drill demand response one year pilot program in three boards and eight schools across the GTA. Program funded by the Ontario Power Authority and in partnership with the City of Toronto, Toronto Hydro, Milton Hydro, Toronto Catholic District School Board, Halton District School Board and the Halton Catholic District School Board. This program is based on a social marketing campaign and the implementation of specific energy drill protocols. Senior program advisor.

- Burlington Hydro. Design of a partnership with Canada Centre for Inland Waters and BHI to promote awareness related to opportunities for commercial building retrofits and distributed generation (gas and solar) for BHI's largest customers. Project manager.

- Association of Canadian Distillers. Design of a pilot social marketing and employee engagement program for a member manufacturing company. Project manager.

IndEco

DAVID HEENEY

President

David Heeney has done management consulting in energy and environment strategy and policy, management systems, technology assessment and training since 1978 both in Canada, US and abroad. One of his distinctive capabilities is to quickly see through a morass and identify the central kernel.

David's consulting projects have covered a wide range of energy and environment issues, including conservation and demand side management (DSM/CDM), climate change, emissions reductions, and environmental management and information systems. He has done extensive work for both public, private and third sector clients in energy efficiency programs – both design and program evaluation, life-cycle assessment, performance indicators (in particular sustainability indicators), full-cost accounting, and the development and use of economic instruments to achieve goals such as the virtual elimination of toxics. He has developed innovative strategic planning, computer modeling and communications and workflow management tools to assist decision-makers to deal with the energy, environment and business challenges they confront.

EXPERTISE

- Electricity and natural gas markets and energy regulation in Ontario
- DSM/CDM and renewable energy policy analysis, program development, implementation and training
- Monitoring and evaluation of CDM programs
- Strategic planning
- Municipal energy and environmental management

EMPLOYMENT HISTORY

- President, IndEco Strategic Consulting Inc. (1994 – present)
- Partner, Hickling (1992 – 1994)
- President, VHB·Hickling (1991-1992)
- Partner, VHB Research & Consulting Inc. (1988-1991)
- President, Heeney Associates (1987)
- Senior Analyst, Ontario Waste Management Corporation (1982-1986)
- Consultant, Middleton Associates (1980-1982)
- Project Analyst, Grande Prairie School District Energy Conservation Program (1979-1980)

PROFESSIONAL QUALIFICATIONS

Master of Environmental Design (Environmental Science), University of Calgary (1980)

Bachelor of Science, University Scholar, McGill University (1977)

APPEARANCES

1992	Joint Board, North Simcoe Waste Management landfill EA, on behalf of the North Simcoe Waste Management Association regarding evaluation methods in environmental assessment
2003	Ontario Energy Board, on behalf of Enbridge Gas Distribution Inc. regarding their DSM framework and incentive mechanisms
2005	Ontario Energy Board, on behalf of the Canadian Energy Efficiency Alliance on DSM/CDM and the 2006 Electricity Distributors Rate Case
2005	Ontario Energy Board, on behalf of Low-Income Energy Network on the TRC Guide in EB-2005-0523

SELECTED PROJECTS

Strategic/business planning

- BC Hydro. Development of a comprehensive framework for the management of low-income customers including DSM and customer care. Project manager.

- Ontario Power Authority. Development of an input-output model which calculated green employment in the Ontario economy as a result of particular energy efficiency, energy conservation and demand management programs and policies. With Dr. Atif Kibursi. Project manager.

- Energy Efficiency Office, City of Toronto. Development of the Report on the Development of the Energy Plan for Toronto. Project manager.

- Social Housing Services Corporation. Development of strategies for CDM program options with various partners including CMHC, OPA, NRCan and other natural gas and electric utilities.

- Conservation Bureau. Conducted a residential fuel choice study involving a review of existing models and forecasts and the development of scenarios for residential fuel-substitution from electricity to natural gas in Ontario. Project manager.

- Conservation Bureau. Provision of guidance on business planning and strategy related to the planning, coordination and reporting functions of the Bureau. Senior technical advisor.

- Energy Efficiency Office, City of Toronto. Development of a Sustainable Energy Business Plan for the Energy Efficiency Office for 2002. Project manager.

- City of Toronto. Development of the City of Toronto's Implementation Plan for the Environmental Plan. Senior advisor.

- CN Rail. Development of a business strategy for the implementation of an environmental management system for facilities across North America in partnership with Retech. Project manager.

- Brewers of Ontario. Development and implementation of a business strategy for enhancement and recognition of environmental performance in packaging. Senior advisor.

- Brewers of Ontario. Senior policy advisor on the development of an environmental strategy including opportunities for reducing energy use and emissions in new facilities and vehicles.

DSM/CDM planning, program development and implementation

- Toronto Catholic District School Board. Design and implementation of the Energy Drill demand response pilot program in three boards and eight schools across the GTA. Program funded by the Ontario Power Authority and in partnership with the City of Toronto, Toronto Hydro, Milton Hydro, Toronto Catholic District School Board, Halton District School Board and the Halton Catholic District School Board. Senior technical advisor.

- Milton Hydro. Design and implementation of Milton Hydro's Energy Drill pilot demand response program. Project manager.

- Conservation Bureau. Development of low-income program options. Senior technical advisor.

- Development of 2006 CDM plans (post third tranche) for Milton Hydro and Burlington Hydro. Project manager.

- Development of 2005 CDM Plans (third tranche) for Milton Hydro, Brantford Power, Brant County Power, Burlington Hydro and Kitchener-Wilmot Hydro. Project manager.

- Milton Hydro. Senior technical advisor in the preparation of Milton Hydro's 2004 DSM Plan (with Fraser & Company).

- Toronto Hydro. Senior technical advisor in the investigation of options for Toronto Hydro to reduce customers' bills including an illustrative approach for 2003 to CDM (with Fraser & Company).

- Toronto Hydro and Milton Hydro. Senior technical advisor in the identification and evaluation of opportunities for DSM for local distribution companies (with Fraser & Company).

- Energy Efficiency Office, City of Toronto. Identification and evaluation of opportunities for strengthening partnerships with Toronto Hydro through joint work in DSM. Project manager.

- Canadian Gas Association and City of Toronto. Senior advisor in the development of a concept and successful proposal to the Climate Change Action Fund for a series of energy efficiency workshops across Canada.

- Ontario Hydro. Comparison of gas-fired and electric commercial chillers. Project manager.

- Ontario Ministries of Energy, Environment and Transportation. Reducing energy use and emissions in Ontario's transportation sector. Project manager.

- Ontario Ministry of Energy. Compressed natural gas market potential in Southwestern Ontario. Project manager.

- Canada Mortgage and Housing Corporation. Implications of energy retrofit on municipal by-laws. Project manager.

- Ontario Hydro. Advisor on the impact of alternative energy areas on the bulk electricity system.

- Ontario Ministry of Housing. Senior advisor on the energy impact of urban development standards.

Program/portfolio evaluation, measurement and verification in DSM/CDM

- Ontario Power Authority. Evaluation of the Powerstream and Veridian peaksaver Neighbour Referral Program. Work is on-going and involves developing an Evaluation Plan for conducting process and impact evaluations and implementing the evaluation activities. Process and impacts evaluations being conducted include: a survey of program participants, non-participants and those referred and interviews with LDC program staff to evaluate the design of the program and why customers did or did not participate; analysis of the tracking sheets, and other process documents, to evaluate the processes employed by the LDCs; and calculating the cost per referral to the program including and excluding incentives. Project manager.

- Burlington Hydro. Prepared the CDM portfolio evaluation for Burlington Hydro's 2005 CDM portfolio and the regulatory approvals application to obtain post-third tranche 2006 CDM funding for new program initiatives. OEB application was successful. Worked on the evaluation of the 2006 and 2007 CDM portfolios. Work involved cost effectiveness testing (comparing actuals to forecast), an assessment of the process for program delivery and recommendations for the future, as part of OEB annual CDM filings. Project manager.

- Milton Hydro. Prepared the CDM portfolio evaluation for Milton Hydro's 2005 CDM portfolio and the regulatory approvals application to obtain post-third tranche 2006 CDM funding. Prepared the filing for the OEB on program evaluation for the 2007 portfolio, which involves cost effectiveness testing (comparing actuals to forecast) for the programs approved under the supplemental funding application, an assessment of the process for program delivery and recommendations for the future. Project manager.

- Kilowatt Corporation. Preparation of financial evaluations of optional program designs for various CDM programs for the Ontario commercial sector. Work is ongoing. Project manager.

- Burlington Hydro. Developed a monitoring and reporting tool for Burlington Hydro for each of their 2005-2008 CDM programs. This tool was developed to assist Burlington Hydro to track resources and savings from each of their programs and to assist in the preparation of quarterly and annual CDM reports to the OEB. Project manager.

- Social Housing Services Corporation. Work involved the development of a computer-based financial tool to optimize and track the financial contributions of participating funders. Project Manager.

- Ontario Power Authority. Assisted the OPA to design and launch the $400M program for LDC CDM by developing a tool for use by LDCs and the OPA to track and report on savings and other performance metrics of CDM programs. Senior advisor.

- Canadian Gas Association. Work involved the preparation of a program evaluation prepared for CGA on the success of the workshop programs conducted by various natural gas LDCs across Canada to increase awareness regarding conservation and renewables among building owners and managers, engineers and architects, and municipalities. The evaluation was based on questionnaires and personal interviews. Senior advisor.

- Milton Hydro. Design of pre-and post seminar questionnaires to evaluate the success of the CDM awareness program for general service customers. Work involved the design and delivery of questionnaires to participants to evaluate awareness effectiveness and interest in participation in Milton Hydro's DR programs. Project manager.

- Enbridge Gas Distribution. With Navigant consulting, provided advice on improvements to Enbridge's DSM framework that included its evaluation and audit protocols. Senior Advisor.

- Expert CDM evaluation witness on behalf of Low-Income Energy Network at the OEB on the appropriate evaluation framework for CDM including how to calculate the TRC (free-riders, measure life, attribution, etc), the nature of any audit required and the treatment of input assumptions approvals by the OEB.

- Expert DSM evaluation witness on behalf of Enbridge Gas Distribution at the OEB on the appropriate DSM framework, including the evaluation framework. T his included how to calculate the TRC (free riders, attribution, overall treatment of input assumptions etc), SSM, the role of the Audit Subcommittee and Consultative, the audit and audit protocol.

DSM/CDM best practices

- Low-Income Energy Network. Preparation of written evidence, oral testimony and input to argument for best practices for TRC calculations for low-income programs. Project manager.

- Enbridge Gas Distribution. Senior policy advisor in survey on regulated incentive mechanisms and the survey on best practices in regulated DSM in North America with Navigant.

- Canadian Energy Efficiency Alliance. Provision of written evidence, oral testimony and input to argument in OEB's 2006 EDR proceeding on best practices for electric utilities on CDM. Project manager.

- Enbridge Gas Distribution. Senior advisor in the development of the DSM regulatory framework and incentive mechanism with Navigant.

Training

- Design Science Laboratory and UN International School in New York City. Facilitated a diverse group of participants in the Design Science Laboratory held at the United Nations and the United Nations International School in New York City. The ten day program provided the participants with classroom interactive instruction on planning methodologies, the millenium development goals (MDGs), and facilitated the group in developing strategies for meeting the goals. Strategies developed were presented to United Nations representatives, and published in a book. Senior trainer.

- Milton Hydro. Design and delivery of a seminar series to the utility's business customers on the electricity market, smart meters and demand response and opportunities for the facilities to save energy. Project manager and senior trainer.

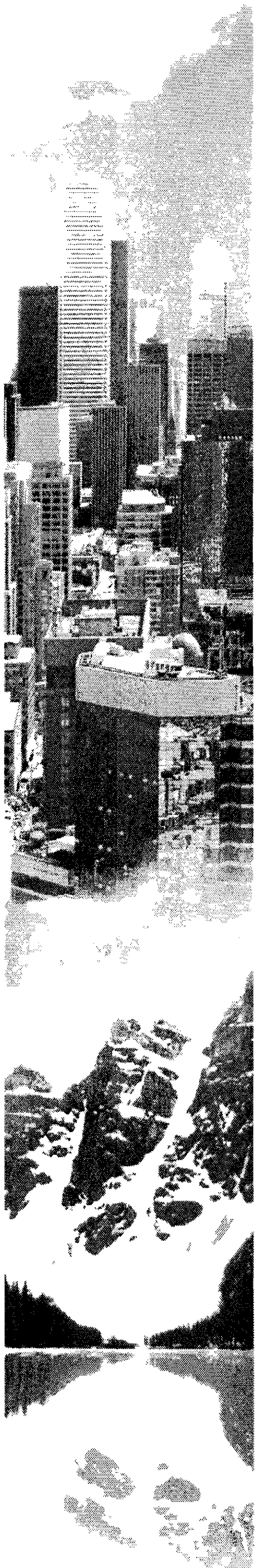
- Burlington Hydro. Design and delivery of customized one on one staff training on calculating the Total Resource Cost Test for the utility's conservation and demand management portfolio and to meet regulatory reporting requirements. Project manager and senior trainer.

- CIDA. Building capacity for climate change in Cuba. With the University of Toronto development and delivery of training modules for senior management in the Ministry of Basic Industry on strategic planning and business development for implementing programs such as energy conservation and renewable programs to address climate change. Project manager.

- BAIF and IDRC. Member of a three member training team for a week-long course delivered to BAIF in Pune, India on monitoring and evaluation of development projects on behalf of the International Development and Research Centre. Senior trainer.

- Beijing Environmental Monitoring Centre. Member of a three member team of trainers that delivered a course to the Beijing Environmental Monitoring Centre in Beijing China on developing inventories of greenhouse gas emissions and the development of strategies for reducing emissions. The project consisted of two training sessions of approximately one week each. In the first, concepts and methodologies were provided to staff of the BEMC in order to allow them to develop a preliminary inventory and strategies. A second session, four months later, involved working with the staff to elaborate upon and refine their work on an emissions inventory for the Province of Beijing. Mr. Heeney assisted the members of the Chinese team focusing primarily on transportation energy use and emissions, and he presented results of the work at a conference of Chinese government representatives in Beijing.

IndEco



Shona Adamson

Senior Consultant

Shona is an environmental scientist with experience in a broad range of issues, and a special focus on energy and conservation and demand management. She has a solid background in environmental science, enriched by an excellent understanding of the interdisciplinary nature of environmental and energy management.

Shona's consulting projects have focused on diverse aspects of DSM/ CDM - strategic planning, program development, program management and implementation, program evaluation, regulatory approval, stakeholder consultation and training. Shona has done work for a broad range of both public and private sector clients, including electric and gas LDC's and municipal and provincial organizations.

Expertise

- Electricity and natural gas DSM/CDM program development, implementation, evaluation, and training
- Energy regulation in Ontario
- Climate change mitigation and adaptation

Employment History

- Senior Consultant, IndEco Strategic Consulting Inc. (2006 – present)
- Consultant, IndEco Strategic Consulting Inc. (2003 – 2006)
- Research Associate, Department of Geography, University of Guelph. (2000 – 2003)
- Course Instructor, Department of Geography, University of Guelph. (2001 – 2002)
- Graduate Teaching Assistant, Department of Geography, University of Guelph. (2000 – 2002)
- Program Coordinator, Canadian Environmental Defense Fund. (1999 – 2000)
- Research Assistant, Environmental Adaptation Research Group, Environment Canada. (1997 - 1998)

Professional Qualifications

Master of Science (Geography), University of Guelph, Ontario

Honours Bachelor of Science (Physical and Environmental Geography and Environmental Studies) University of Toronto, Ontario. Graduated with High Distinction

AWARDS

2001	Ontario Graduate Scholarship
2001	Ontario Graduate Scholarship in Science and Technology
2001	Board of Graduate Studies Research Scholarship
2000	Arthur D. Latornall Graduate Travel Scholarship
2000	University Graduate Scholarship
1996 – 2000	University of Toronto Deans List
2000	The Douglas Pimlott Award
1999	The Alpar Undergraduate Scholarship
1998	St Michael's Foundation Incourse Scholarship

SELECTED PROJECTS

Strategic/business planning

- BC Hydro. Design of a framework for the treatment of low-income customers including DSM and customer care. Senior advisor.
- Ontario Power Authority. Assisted the OPA to design and launch the $400M program for LDC CDM by providing advice on the design of a tool for use by LDCs and the OPA to track and report on savings and other performance metrics of CDM programs. Senior analyst.
- Ontario Power Authority. Assisted the OPA to design and launch the $400M program for LDC CDM including establishing the rules for funding, the application process and the contract elements, and developing program templates and detailed designs for the two commercial 'standard programs in a box' for the LDCs. Work completed in partnership with Navigant. Senior analyst.
- Energy Efficiency Office, City of Toronto. Development of the Report on the Development of the Energy Plan for Toronto. Senior researcher and policy advisor.
- Conservation Bureau. Provision of business planning and strategic advice. This included guidance on the creation and implementation of internal policy and administrative structures, and the identification of staffing and budgeting requirements for the planning, coordination and reporting function. It also included project management advice to the

OPA on the work planning and scheduling of tasks for the preparation of the 2006 Chief Energy Conservation Officer's 2006 Annual Report and the preparation of the LDC and other market player scorecards for the 2006 CECO Annual Report. Senior policy advisor.

DSM/CDM planning, program development, implementation, monitoring and evaluation

- UHN. Design and delivery of 3-year (2007-2009) comprehensive energy management program including social marketing, employee engagement, retrocommissioning, operator training and audit and retrofit. Program piloted at TWH in 2007 and is ongoing. Work has begun on program delivery to TGH in 2008. Program will begin at Princess Margaret in 2009. Project manager.

- MaRS. Development of education and awareness profiles in 20 MaRs buildings as part of development of Energy Management Plan with Finn Projects. Next step is to develop a Community Action Plan to implement a coordinated set of energy policies and programs among the 20 buildings. Project manager. Work is ongoing.

- Ontario Power Authority. Evaluation of the Powerstream and Veridian peaksaver Neighbour Referral Program. Work is on-going and involves developing an Evaluation Plan for conducting process and impact evaluations and implementing the evaluation activities. Process and impacts evaluations being conducted include: a survey of program participants, non-participants and those referred and interviews with LDC program staff to evaluate the design of the program and why customers did or did not participate; analysis of the tracking sheets, and other process documents, to evaluate the processes employed by the LDCs; and calculating the cost per referral to the program including and excluding incentives.

- Bluewater Power. Delivery of monitoring and reporting services for ERIP. Project manager.

- Barrie Hydro. Delivery of ERIP in 2007. Program manager.

- NEPA Group. Delivery of ERIP in 2007. Senior analyst.

- NEPA Group. Provided guidance on the preparation of workplans and budgets for applications to the OPA LDC CDM fund. Senior analyst.

- Oakville Hydro. Provide guidance on the preparation of workplans and budgets for applications to the OPA LDC CDM fund. Senior analyst.

- Kitchener-Wilmot Hydro, Waterloo North Hydro and Cambridge North Dumfries Hydro. Assist in the preparation of application to the OPA for funding for the delivery of LDC standard programs. Senior advisor.

- Oakville Hydro. Preparation of OEB application to exceed 20% rule for CDM spending. Senior advisor.

- Enbridge Gas Distribution. Conduct of a financial audit of the TAPs Program. Project Manager.

- Enbridge Gas Distribution. Testing of software for the tracking and evaluation of Enbridge DSM programs. Project manager.

- Toronto Atmospheric Fund. Development of a municipal lighting program design for Toronto Atmospheric Fund. Work involved review of energy forecasts and needs in the GTA, survey of existing municipal and LDC lighting programs in the GTA, evaluation of measures (including TRC calculations), and preparation of written description. Senior researcher and advisor.

- Burlington Hydro. Development of detailed program designs, implementation plans marketing and advertising programs, as well as monitoring and evaluation systems for the utility's lighting retrofit programs for its general service customers, municipal customers, and for its residential new construction program. Senior policy researcher and policy advisor.

- Burlington Hydro. Development of strategy and templates for meeting OEB CDM reporting requirements. Senior advisor.

- Milton Hydro. Development of 2006 CDM plan (post-third tranche) and the regulatory submission to the OEB regarding the plan. CDM regulatory policy advisor.

- Burlington Hydro. Development of 2006 CDM plans (post-third tranche), regulatory submission regarding the plan, and preparation of interrogatory responses. Senior advisor.

Hard to reach customers CDM/DSM

- GLOBE. Development of policies and strategies for presentation at OEB proceeding on low income. Work is ongoing.

- Enbridge Gas Distribution. Benchmarking Enbridge customer care policies including those for seniors and hardship customers with those of Canadian and US gas utilities. Senior analyst.

- OPA. Development of program design for Multi-Family Buildings Program with LURA. Program manager.

- Social Housing Services Corporation. Development of strategies for CDM program options with various partners including CMHC, OPA, NRCan and other natural gas and electric utilities. Senior analyst.

- Enbridge Gas Distribution. Review of existing security deposit policies and making recommendations for improvement, including the integration with low-income DSM. Senior advisor.

- OPA. Development of conservation program concepts for social housing, low-income tenants in private buildings, and low-income homeowners. Senior advisor.

- Brantford Power. Design of the Conserving Homes Program pilot, the leading Canadian low-income CDM program. Design included detailed program design, the monitoring and evaluation system for the program, and training for the project implementation team. Senior researcher.

- Low-Income Energy Network. Case manager for intervention in Union Gas' 2006 DSM proceeding (EB-2005-0507).

- Low-income Energy Network. Case manager for intervention at OEB in EB-2005-0523 on CDM regulatory framework.

- Low-Income Energy Network. Fundraising through a Trillium proposal to secure funds and then to use the funds to create the LIEN website and to hold the first annual conference on low-income energy matters with LIEN members and other interested NGO's, government and other participants. Senior advisor.

- Low-Income Energy Network. Development of a low-income energy efficiency program template for electric LDC's to adopt for low-income homeowners and tenants who pay their electricity bills directly. Work was funded by Ministry of Energy and Toronto Atmospheric Fund. Senior advisor.

- Toronto Environmental Alliance. Research on the development of a comprehensive energy management strategy for low-income consumers including emergency assistance, rate assistance, education and CDM programs. Project researcher.

CDM/DSM best practices

- Canadian Gas Association. Preparation of DSM best practices on monitoring and evaluation in Canadian gas utilities, which updates previous best practices DSM study. Senior consultant.

- Canadian Gas Association. Preparation of policy paper on declining average use across gas utilities in Canada and making recommendations for addressing this situation in rates. Senior advisor.

- Electricity Distributors Association. Preparation of presentation at EnerCom 2007 on comparison between conservation and demand management in Ontario and US jurisdictions. Senior advisor.

- Enbridge Gas Distribution. Conduct of survey to identify best practices on regulatory incentive mechanisms for CDM in regulated natural gas and electric utilities in North American jurisdictions with Navigant Consulting. Senior researcher.

- Enbridge Gas Distribution. Conduct of survey of natural gas DSM in North American jurisdictions with Navigant Consulting. Survey involved identification of practices related to regulatory approvals, budget and target setting, incentive mechanisms and revenue adjustment mechanisms. Senior researcher.

Training

- Electric LDCs. Provision of training on conservation and demand management (CDM) to various Ontario electric LDCs. Three training sessions have been delivered to date. Work is ongoing. Senior trainer.

- Ontario Independent Electricity System Operator. Design and delivery of a series of interviews with hospitals and long term care facility managers to discuss how the facility will cope with the change from the regulated price plan to the wholesale electricity market. The interviews will provide the basis for a report IndEco will prepare documenting the sector profile, the education and training needs and how the IESO should address them. Work is ongoing. Project manager.

- NEPA Group (10 electric utilities), Bluewater Power and Barrie Hydro. Design and delivery of training webinars for the business customers of each of these utilities on energy conservation and the Electricity Retrofit Incentive Program, including incentives available, how to apply, and eligible measures. Also held webinars for the channel partners of these utilities on how to access the program for their customers and the incentives. Senior trainer.

- NEPA Group, Barrie Hydro and Bluewater Power. Designed and delivered training workshops to the customers and to the channel partners of how the Electricity Retrofit Incentive Program works and how they can access it. Senior trainer.

- Brant County Power. Provision of custom training session to the CSRs of the utility on how to respond to customer inquiries related to the Ontario Power Authority conservation and demand management programs that the utility was delivering. Project manager and trainer.

- Burlington Hydro. Design of awareness and training events and presentations to Burlington's largest customers on their CDM portfolio and lighting retrofit programs in particular, and design of awareness and training events and presentations to local homebuilders for the new construction lighting program. Trainer.

- Clean Air Partnership. Development and delivery of a training workshop on electricity demand management and demand response - opportunities and barriers for municipalities in Ontario's changing electricity market. Trainer.

- CIDA. Building capacity for climate change in Cuba. With the University of Toronto development and delivery of training modules for senior management in the Ministry of Basic Industry on strategic planning and business development for implementing programs such as energy conservation and renewable programs to address climate change. Trainer.

- University of Guelph. Course instructor for the Management of the Biophysical Environment course in the department of geography. Work involved design and delivery of the course, development of course material and student evaluation.

- University of Guelph. Teaching assistant for several courses including Statistics, Introduction to the Biophysical Environment, and Geomorphology in the department of geography.

Stakeholder engagement and social marketing

- University Health Network. Design and delivery of employee engagement and social marketing programs to achieve energy and water savings at Toronto Western and Toronto General Hospitals (2008-2010). Project manager.

- BC Hydro. Design and delivery of a strategic planning session to develop a management framework for low-income customers. Facilitator and advisor.

- Ontario Power Authority. Development of materials for presentation at stakeholder meetings of the OPA's Program Design Advisory Group and Program Operations Advisory Groups. Senior researcher and policy advisor.

- Low-Income Energy Network. Case manager for LIEN interventions before the OEB on electricity policy (e.g. RPP, NGEIR).

- Canadian Energy Efficiency Alliance. Advise on the design and delivery of two awareness and training CDM workshops for LDCs and other stakeholders. Senior advisor.

- Association of Canadian Distillers. Design of a social marketing and employee engagement pilot program for a member manufacturing company. Senior program advisor.

INDECO

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providing environmental and energy consulting to private, public and non-governmental organizations

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~~Ontario Energy Board~~ ~~Commission de L'energie de l'Ontario~~

Appendix A

REVISED BLACKLINED DRAFT DEMAND SIDE MANAGEMENT GUIDELINES FOR NATURAL GAS DISTRIBUTORS

EB-2008-0346

Date: ~~January 26,~~ February 20, 2009

TABLE OF CONTENTS

Page

~~TABLE OF CONTENTS~~1.0 OVERVIEW 5
1.1 Background 5
1.2 Overview of Draft Guidelines 5
2.0 COST EFFECTIVENESS 6
2.1 TRC Calculation 7
2.2 TRC Benefits 9
2.2.1 Avoided Costs 9
2.2.2 Natural Gas Savings 10
2.3 Inputs and Assumptions ~~(Changes Proposed)~~ 11
2.4 TRC Costs 11
2.4.1 Equipment Costs 11
2.4.2 Program Costs 12
2.5 Adjustment Factors in the TRC Test for Assessing DSM Programs 14
2.5.1 Free Riders 14
2.5.2 Attribution 15
2.5.3 Spillover ~~(New)~~ 16
2.5.4 Persistence ~~(Changes Proposed)~~ 16
2.6 Fuel Switching ~~16~~17
2.7 Pilot Programs ~~16~~17
3.0 DSM BUDGETS AND TARGETS ~~(Changes Proposed)~~ 17
3.1 Budget Determination 17
3.2 Budget Term and Reporting ~~17~~18
3.3 Adjustments to an Approved Plan 18
3.4 Targeted Program Spending ~~18~~19
3.5 TRC Savings ~~Targets~~Metrics 19
3.6 Market Transformation ~~Targets~~Metrics 19
3.7 Low-income Customer Program ~~Targets (Changes Proposed)~~Metrics 20
4.0 LOST REVENUE ADJUSTMENT MECHANISM (LRAM) 20
4.1 Eligible Programs 21

TABLE OF CONTENTS
(continued)

Page

4.2 Calculation of LRAM 21

4.3 Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) 22

4.4 Timing of LRAM Application 22

5.0 INCENTIVE PAYMENT MECHANISMS ~~(Changes Proposed)~~ 22

5.1 Eligible Programs 22

5.1.1 Shared Savings Mechanism (SSM) for Resource Acquisition Programs 23

5.1.2 Market Transformation Incentive .... ~~24~~23

5.1.3 Low Income Customer Programs Incentive 24

5.2 Shared Savings Mechanism Variance Account (SSMVA) 24

5.3 Timing of Application 24

6.0 PROGRAM EVALUATION AND AUDIT .... ~~25~~24

6.1 Evaluation Plan 26

6.2 Program Type Specific Guidelines .... ~~27~~26

6.2.1 Direct Acquisition Programs 27

6.2.2 Market Support Programs .... ~~28~~27

6.2.3 Custom Projects 28

6.2.4 Market Transformation Programs 29

6.2.5 Low Income Customer Programs 29

6.3 Implementation of Updated Input Assumptions 29

6.4 Evaluation Report 30

6.5 Independent Third Party Review .... ~~32~~31

7.0 DSM CONSULTATIVE 32

8.0 ACCOUNTING TREATMENT .... ~~34~~33

8.1 Funding of DSM Programs .... ~~34~~33

8.2 Cost Allocation 34

8.3 Revenue Allocation 34

8.4 Demand Side Management Variance Account (DSMVA) .... ~~35~~34

8.5 Carbon Dioxide Offset Credits Deferral Account (CDOCDA) .... ~~35~~34

Page

8.6 Recording of DSM Spending Not Funded Through Distribution Rates 35

9.0 ANNUAL REPORTING GUIDELINES ~~(New)~~ 35

10.0 ADMINISTRATION 37

10.1 Filing Guidelines (New) 37

10.1.1 Program Funding through Distribution Rates 37

10.1.2 Lost Revenue Adjustment Mechanism (LRAM) 39

10.1.3 Shared Savings Mechanism (SSM) and Other Financial Incentives 40

10.1.4 Adjustments to an Approved Plan 41

TABLE OF CONTENTS
(continued)

Page

1.0 OVERVIEW

1.1 Background

The Ontario Energy Board (the Board) determined the original regulatory framework for gas distributor ("distributor" or "utility") sponsored Demand Side Management ("DSM") programs through guidelines established in its EBO 169-~~111~~III Report of the Board dated July 23, 1993. DSM programs are programs which assist distributor customers in reducing their natural gas consumption. Union Gas Limited ("Union") and Enbridge Gas Distribution Inc, ("~~EGO~~EGD") filed DSM plans in response to the directives of the Board in the EBO 169-~~111~~III Report until 2006.

In 2006, the Board conducted a hearing on generic issues related to distributor DSM activities (EB-2006-0021).

The Board's August 25, 2006 decision in the generic proceeding dealt with a large number of issues relating to DSM. A rules-based and framework approach was established where appropriate and practical, which the Board expected would result in significant regulatory savings for the parties, the Board and, ultimately, for ratepayers. Below is a list of the broader matters that were agreed by stakeholders and decided by the Board in that decision.

- A three-year term for the first DSM plan
- Processes for adjustments during the term of the plan
- Formulaic approaches for DSM targets, budgets, and distributor incentives
- Determination of how costs should be allocated to rate classes
- A framework for determining savings
- A framework and process for evaluation and audit
- The role of distributors in electric conservation and demand management activities and initiatives

In a separate decision dated October 18, 2006, the Board approved the input assumptions based on which Union and EDG filed their three-year DSM plans. DSM plans for each of Union and EDG were subsequently approved by the Board, and expire in 2009.

1.2 Overview of Draft Guidelines

On October 31, 2008, the Board initiated a consultation process on the development of Demand Side Management Guidelines for Natural Gas Distributors (the "Guidelines") to assist in the development of next generation of gas distributor DSM plans. The Guidelines are expected to be applicable to natural gas distributor DSM initiatives beginning in 2010, and should be used in the preparation of distributor DSM plans. Those plans, including budgets, program targets and other related matters, will be considered by the Board in the context of rate proceedings for each of the distributors.

These draft Guidelines have been developed by Board staff following consultations with gas distributors and other interested stakeholders. The draft Guidelines largely consolidate existing Board policies in relation to DSM activities as reflected in the following DSM~~-~~-related decisions and orders of the Board:

- EBO 169-~~111~~III Report of the Board dated July 23, 1993; and
- The decisions for Phases I, II, and III of the DSM generic proceeding (EB-2006-0021).

By way of exception, the draft Guidelines propose changes in the following areas:

- Development of inputs and assumptions (section 2.3)
- Adjustment factors in the Total Resource Cost test for assessing DSM programs:

Spillover effects (section 2.5.2)

Persistence of savings (section 2.5.3)

- Development of DSM budgets and targets (section 3.0)

Low-income customer programs

- Incentive payment mechanisms (section 5.0)

Shared savings mechanism for resource acquisition programs

Market transformation incentive

Low income customer programs Incentive

- Program evaluation and audit (section 6.0)
- Annual reporting guidelines (section 9.0)
- Filing guidelines (section 10.0)

For symmetry, the draft Guidelines incorporate elements of the “Guidelines for Electricity Distributor Conservation and Demand Management” issued by the Board in 2008 (EB-2008-0037).

2.0 COST EFFECTIVENESS

The Total Resource Cost (TRC) test is the appropriate test to measure cost effectiveness. This test should be used by utilities when evaluating the cost effectiveness of a measure or program to determine ~~whether~~the cost-effectiveness of a measure or program~~ can be considered for inclusion in the portfolio~~.[1]

The TRC test measures the benefits and costs of DSM efforts from a societal perspective. Under the TRC test, benefits are driven by avoided resource costs, which are the marginal costs that are avoided by not producing and delivering the next unit of natural gas to the customer. In addition, it includes the reduction in use of other resources such as electricity, water or other resources. Marginal costs (or avoided costs) include natural gas costs (both system and customer) and distribution costs (e.g., pipes, storage, etc.).

Costs in the TRC test are the costs of any equipment and program support costs associated with delivering that equipment to the marketplace.

Benefits	**Costs**[2]
Avoided natural gas supply costs	Equipment costs
Other avoided resource costs	Distributor program costs
~~Avoided natural gas supply costs~~	~~Equipment costs~~
~~Other avoided resource costs~~	~~Distributor program costs~~

This section sets out the expectations regarding the benefit-cost analysis for DSM programs.

2.1 TRC Calculation

Evaluating the cost effectiveness of DSM ~~is~~can be done in stages at many different levels, including technology or measure, program, and portfolio. The TRC test should be performed at each level, as appropriate. For some generic examples of how to apply the TRC Test see Appendix A of the Guidelines for Electricity Distributor Conservation and Demand Management (EB-2008-0037).

At the most detailed level, a TRC test ~~should~~can be performed to evaluate the cost effectiveness of a measure or technology. At the technology level, the TRC test takes into account the benefits, which are the avoided natural gas supply costs and other avoided resource costs, and the equipment costs. There are no other adjustments to the TRC test at this stage of the evaluation.

~~Once a technology has proven to be cost effective, a program can be designed using that technology.~~ ~~*Once the program costs have been assessed, the TRC test*~~ ~~will~~ *be*

[1] ~~California Public Utilities Commission. (2001) Standard Practice Manual: Economic Analysis of Demand-Side Management Programs and Projects~~National Action Plan for Energy Efficiency (2008). Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers. Energy and Environmental Economics, Inc. and Regulatory Assistance Project.

[2] In the case of fuel switching measures, the costs of the other fuels should be included.

~~*performed again to evaluate the cost effectiveness of the program. At the program level, the TRC test takes into account the following:*~~

- ~~*The costs and benefits as estimated at the technology level;*~~
- ~~*The distributor program costs; and*~~
- ~~*Further adjustments to account for free ridership, persistence of savings, etc.*~~

~~*Finally, several programs are bundled together, further indirect costs are included and the TRC test is carried out once again to evaluate the cost effectiveness of the portfolio. This three layered structure; technology or measure, program and portfolio, is key to performing TRC analyses.*~~

The results of the TRC test should be expressed as a net present value (NPV). As a NPV assessment, the TRC test sums the streams of benefits and costs over the lifetime of the equipment/technology and uses a discount rate to express these streams as a single "current year" value. Thus, the NPV_{TRC} is the net ~~TRC~~ discounted value of the benefits and costs over a specified period of time (usually dictated by the equipment life of the DSM technology).

The TRC test is a measure of the change in the total resource costs to society, excluding externalities, of the DSM program. If the NPV_{TRC} is positive, or the benefit to cost ratio exceeds 1, indicating that benefits exceed costs~~, the measure, program or portfolio is considered~~ and is cost effective from a societal perspective.

Since the resource acquisition portion of the utility shared savings mechanism is based on sharing a portion of the customer net savings (TRC) that the utility programs generate, it is anticipated that utilities will be incented to increase TRC where possible at a portfolio level. However, in some cases to facilitate customer needs it may be necessary to undertake certain projects that are individually below a TRC ratio of 1.

Once the program costs have been assessed, the TRC test can *be performed again to evaluate the cost effectiveness of the program. At the program level, the TRC test takes into account the following:*

- *The costs and benefits as estimated at the technology level;*
- *The distributor program* costs, excluding verification, measurement and evaluation *costs; and*
- *Further adjustments to account for free ridership,* spillover, *persistence of savings, etc.*

Finally, several programs are bundled together, further indirect costs are included and the TRC test is carried out once again to evaluate the cost effectiveness of the portfolio. This three layered structure; technology or measure, program and portfolio, is key to performing TRC analyses.

The NPV_{TRC} formula is as follows:

The NPV_{TRC} formula is as follows:

$$NPV_{TRC} = B_{TRC} - C_{TRC}$$

where;

$$B_{TRC} = \sum_{t=1}^{N} \frac{AC_t}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^{N} \frac{UC_t + PC_t}{(1+d)^{t-1}}$$

and,

B_{trc}	=	the benefits of the program
C_{trc}	=	the costs of the program. Where a measure includes fuel switching for a given end use, the cost of the other fuel must be included in the cost component of the TRC formula.
AC_t	=	avoided costs in year t
UC_t	=	distributor program costs in year t
PC_t	=	participant cost in year t
N	=	number of years for the analysis (i.e., the equipment life of the DSM technology)
d	=	discount rate.

Note: Distributors should use a discount rate equal to the incremental after-tax cost of capital, based on the latest prospective capital mix, debt and preference share cost rates, and approved rate of return on common equity.

2.2 TRC Benefits

2.2.1 Avoided Costs

As noted above, the TRC test assesses DSM costs and benefits from a societal perspective. The benefits are defined as "avoided costs." This represents the benefit to society of not having to provide an extra unit of supply of natural gas to the customer. For natural gas distributors, supply costs include the gas commodity and the avoided distribution system costs (e.g., pipes, storage, etc.).

Certain DSM programs may have other benefits, including savings of other energy sources such as electricity, heating fuel oil, propane or water. While these savings are not generally the primary target of the program, the TRC test will accommodate an assessment of savings associated with avoiding the use of these resources. In these cases, the benefits accrue from the avoided costs associated with these resources. Utilities wishing to assess resource savings relating to other energy forms or water will need to use avoided cost estimates for those resources in the same manner that natural gas avoided costs are used.

The TRC test involves an analysis over the life-cycle of the DSM measure. To accommodate this, long-term projections of avoided costs should also be undertaken. Also, any DSM measures included in the analysis should have equipment life estimates along with estimates of savings and costs.

Each distributor should calculate avoided costs for natural gas, other energy forms and water that reflect the cost structure and franchise area of the distributor. In order to ensure consistency, a common methodology should be used to determine the costs. The distributors should coordinate the timing for selecting commodity costs so that they are comparable.

The avoided costs should be submitted for review as part of the DSM plan filing and should be in place for the duration of the plan. The commodity portion of the avoided costs should be updated annually.

As avoided costs are long term projections, updating the costs, other than the commodity costs, on a multi-year cycle should not cause benefits to be significantly under or overstated. Regardless of how often the avoided costs are updated, the same avoided costs are expected to be used to calculate both the target and incentive amount. It is therefore anticipated that the relative impact of avoided costs on ~~both the target and incentive amount~~TRC would be minimal.

Estimating the natural gas avoided costs ~~applicable to each customer class~~ should include the following analytical steps:

1. estimate marginal natural gas commodity costs;
2. estimate marginal distribution costs;
3. determine the appropriate costing periods, if applicable; and
4. attribute marginal costs to the costing periods, if applicable.

Marginal cost studies typically involve detailed analyses starting with an understanding of the current costs for gas commodity and distribution (e.g., pipes, storage, etc.).

~~The avoided cost data that distributors should use for calculating the benefits of reducing electricity use will be posted on the Board's website.~~

2.2.2 Natural Gas Savings

The benefits in the TRC test are driven mainly by the annual energy savings (e.g. natural gas ~~savings~~). They are often calculated at the technology level and are commonly referred to as "prescriptive" savings estimates. For programs that rely on prescriptive savings estimates, savings are calculated by multiplying the per unit (i.e., single technology) savings with the number of units installed.

Savings and technology costs should be defined relative to a frame of reference or "base case." To accurately specify the impacts of any given technology, the analyst should know what would have happened in the absence of the technology. The base case technology variable represents the piece of equipment or technology that is being replaced by a more efficient technology. The application of a base case technology can vary; for example, in the case of a DSM program consisting of a residential programmable thermostat, the base technology would be a manual thermostat. In the example of a program consisting of a high efficiency furnace, the base case equipment would be the homeowner's current furnace. At a minimum, the base case technology should be equal to or more efficient than the technology benchmarks mandated in energy efficiency standards.

In practice, specifying savings relative to a frame of reference can be simply characterized by the three general decision types:

- new;
- replacement; or
- retrofit.

In the TRC analysis, equipment life is used to determine the time period over which the net present value analysis is carried out. The equipment life variable represents the number of years that the more efficient equipment installed is assumed to produce natural gas savings. The benefits (i.e., natural gas savings) from an energy efficient piece of equipment are assumed to persist for the life of the equipment. Equipment life is estimated based on the nature of the equipment and an assumed usage pattern.

An important consideration when assessing equipment life is the potential difference between the energy efficient equipment and the "base case" equipment that is being replaced. A simplifying assumption in the case of replacement programs is that the energy efficient equipment lives are the same as in the base case. However, there are some technologies where the energy efficient equipment has a much longer life than the base case equipment, which should be accurately accounted for, when practical.

2.3 Inputs and Assumptions ~~(Changes Proposed)~~

The inputs and assumptions for a selection of measures, covering a range of typical DSM activities/technologies in residential, commercial and industrial applications are being developed by the Board with assistance of an external consultant and with input from distributors and other stakeholders. The approved inputs and assumptions will be posted on the Board's website. Distributors should use this data for undertaking benefit-cost analyses of DSM measures and programs.

Distributors may use other data where appropriate and justified. However, where a distributor uses other data the distributor should provide detailed evidence to justify its use.

2.4 TRC Costs

The TRC includes two types of DSM costs:

1. equipment costs; and
2. program costs.

2.4.1 Equipment Costs

Typically in DSM programs, equipment costs are paid by the participant/customer. Customer equipment costs (sometimes termed “participant costs”) are the costs to purchase the more efficient equipment. They include capital, installation and operating and maintenance (O&M) costs associated with the technologies of the DSM program. It is important to note that the TRC test does not differentiate between who (distributor or customer) pays the cost of the equipment.

Customer costs can be incremental or full depending upon the nature of the energy efficiency investment decision. Incremental equipment costs are defined as the cost of the energy efficient technology above the base case technology. In the same way that the base case is important for specifying the savings, it is also important for specifying the cost of the energy efficient equipment. For example, in a replacement scenario, the cost of the energy efficient technology is typically incremental. In a retrofit or discretionary investment case, the cost of the energy efficient technology would be the full cost of the equipment.

Equipment costs, whether paid by the customer or the distributor, including purchase and installation, should always be defined relative to a base case. It is not enough to know the installed cost associated with the energy efficient equipment used in the program. To calculate the impact of the program, the cost of the equipment that would have been purchased in the absence of the program, the base case, should also be known. The appropriate specification of incremental cost for use in the TRC analysis is the difference between the base case and the energy efficient purchase.

As in the case of savings, there are typically three generic categories for specifying equipment costs, representing the type of investment decision:

- new;
- replacement; or
- retrofit.

The information sources for equipment costs will vary. For residential equipment, retail store prices are appropriate sources of information for many technologies including appliances and “do-it-yourself” water heater or thermal envelope upgrades. It is common practice to specify an average price based on a sample of retail prices. For commercial and industrial equipment, cost data can be more complicated to acquire due to limited access and confidentiality concerns. For larger “custom” projects, invoices or purchase orders, when available, may be ~~necessary~~one method to support the cost estimate.

Equipment that requires O&M expenditures is often not incremental (i.e., those costs would have been incurred in the base case anyway). However, if the energy efficient equipment requires significantly more/less maintenance than its less energy efficient counterpart, the incremental/decreased O&M costs need to be factored into the TRC analysis. There will be exceptions and a proper TRC analysis should incorporate these.

2.4.2 Program Costs

From the perspective of the TRC test, DSM program costs are those incurred by the distributor. These costs include the marketing and support costs associated with delivering the DSM activity. Participant or customer incentive costs, which are considered transfers in the TRC test, are not included in the analysis.

Distributor costs typically cover a number of activities such as marketing and advertising, consulting, channel support, monitoring and evaluation. There are five major categories of distributor costs:

~~(i)~~ (i) development and start-up;
~~(ii)~~ (ii) promotion;
~~(iii)~~ (iii) equipment and installation;
~~(iv)~~ (iv) monitoring and evaluation; and
~~(v)~~ (v) administration.

In practice, all of these costs can be expected for programs that utilities in Ontario might be considering. For an accurate TRC assessment, the distributor should ensure that all costs associated with designing, operating and tracking the programs, other than incentive costs, are accounted for in its TRC analysis.

i. ~~i.~~ Development and Start-up Costs

Development and start-up costs are different from on-going operating costs. For example, initial costs may be incurred to train distributor staff in the use of the equipment or techniques used in a program and usually occur at the early stages of the program's life. Costs of developing DSM plans and procedures are also often concentrated in the early program years. In general, start-up costs are only a small component of the total costs in the life cycle of a DSM program.

ii. ~~ii.~~ Promotion Costs

Promotion costs may be incurred to educate the customer about a DSM program and will vary by program type and level of promotional effort. The cost of promotion depends on the method employed, the market segment and the DSM measures promoted.

Program promotion may also involve trade-offs between increases in promotion costs and expected increases in participation.

As noted above, incentive payments from the distributor to a customer for participation in a program are not a component of the TRC analysis, but still should be included in the distributor's program budget. The incentive merely represents a transfer payment between two parties involved in the program.

iii. ~~iii.~~ Distributor Equipment and Installation Costs

Distributor equipment and installation costs include the costs of any distributor devices needed to operate the programs such as specialized software or tools, as well as any equipment directly installed by the distributor.

iv. ~~iv.~~ Monitoring and Evaluation Costs

This section focuses on the cost to the distributor of monitoring and evaluating a DSM portfolio.

There are two broad categories of evaluation activity: impact evaluation and process evaluation. Impact evaluation focuses on the specific impacts of the program ~~-~~ – for example, savings and costs. Process evaluation focuses on the effectiveness of the program design ~~-~~ – for example, the delivery channel. The costs associated with each of these activities are program costs that need to be included in the TRC analysis~~. Some of these costs will be assigned directly to a specific program or programs, while a portion of the costs are more appropriately assigned across all programs (i.e., at the DSM~~ at the portfolio level~~)~~.

Monitoring and evaluation costs are incurred for systems, equipment and studies necessary to track measurable levels of program success (participants, impacts on consumption and costs) as well as to evaluate the features driving program success or failure. It is important to develop the necessary tracking systems at the time of program design. At a minimum, the tracking system should collect information on the key components that drive the TRC test, including:

- number of participants/installations;
- natural gas savings;
- cost of equipment; and
- distributor program costs.

To facilitate the evaluation of DSM programs and results, utilities should have clearly documented "paper trails."

v. ~~v.~~ Administrative Costs

Administrative costs are generally the costs of staff who work on DSM activities. These costs are often differentiated between support and operations staff. Support staff costs are considered fixed costs or "overhead" that occur regardless of the level of customer participation in the programs. Operations staff costs are variable, depending on the level of customer participation. Utilities should include all staff salaries that are attributable to DSM programs as part of the costs in the TRC analysis.

2.5 Adjustment Factors in the TRC Test for Assessing DSM Programs

In performing a TRC analysis of a DSM program, several adjustments should be made to the benefits side of the equation. These adjustments include:

- free ridership of participants (section 2.5.1);
- attribution of the benefits (section 2.5.2);
- spillover effects (section 2.5.3); and
- persistence of the measures (section 2.5.4).

2.5.1 Free Riders

Free rider adjustments are ~~one of the key components~~a component of the TRC test when it is applied in the assessment of a program. The standard definition of a free rider is "a program participant who would have installed a measure on his or her own initiative even without the program."[3] This participant simply uses the program to offset the cost of installing or undertaking the energy efficient initiative.

Costs and benefits associated with free ridership should be assessed as part of the TRC analysis of a program. In determining overall savings of a program, these participants are excluded from the benefits attributed to the program. The equipment costs associated with these participants is similarly excluded from the cost side of the equation.[4] However, all program costs associated with free riders should be included in the analysis. ~~Programs that have high free ridership are self-evident in the marketplace (i.e., they do not rely on distributor promotion) and are less cost effective since the program costs are included in the TRC calculation while the benefits are not.~~

Assumptions on free ridership should be assessed for reasonableness prior to implementation of the plan or program and should be reviewed and updated ~~on an annual basis~~over the course of the multi-year plan as part of each distributor's ongoing evaluation and audit processes.

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

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

2.5.2 Attribution

~~DSM-related activities could be managed and/or delivered not only by natural gas distributors, but also by others such as electricity distributors, electricity retailers, gas marketers, the Ontario Power Authority and different levels of government.~~

~~A fundamental issue for the evaluation of DSM programs is whether the effects observed after the implementation of a distributor DSM activity can be attributed to that activity (otherwise known as causality) or result from the activities of others.~~

~~While attribution is not a true adjustment to the TRC test, this issue is important in the calculation of a Lost Revenue Adjustment Mechanism ("LRAM"), Shared Savings Mechanism ("SSM") or other financial incentive claims.~~

The concept of attribution has been assessed by the Board in previous proceeding and most recently in EB-2006-0021 where the Board decided:

> "… the Board accepts the centrality principle for purposes of the first multi-year DSM plans, under which the utility would be entitled to 100% of the TRC benefits if it can be demonstrated that it has a central role in a program. That is, as the utilities proposed, if the utility *initiated the partnership, initiated the program, funded the program, or implemented the program.*" (EB-2006-0021 Board Decision with Reasons, August 25, 2006, page 42)

Prohibitive and excessive rules related to attribution have the potential to restrict partnerships that can enhance conservation for Ontario. In the Board's Decision With Reasons in RP-2003-0203, paragraph 6.7.14, page 61, the Board indicated:

> "The Board is not concerned about the Company partnering with others to accomplish TRC savings, based upon the goal of achieving the greatest possible DSM benefits at the lowest cost, and in the simplest way possible."

Attribution of benefits as between a distributor and a non-rate regulated third party will be determined on a case-by-case basis.[5] In order for the distributor to claim 100% attribution of benefits, the distributor should demonstrate that its role was 'central' to the program. ~~The centrality principle as expressed by the Board in proceeding EB-2005-0001 dictates that the distributor plays a central role if the distributor *initiated the partnership, initiated the program, funded the program, or implemented the program.* Centrality is established by the distributor if its financial contribution is greater than 50% of program funding or, where the distributor's financial contribution is less than 50% of program funding, the distributor initiated the partnership, initiated the program or initiated the implementation of the program. Where the distributor's financial contribution~~

[5] See the March 3, 2006 Decision of the Board in proceeding RP-2005-0020/EB-2005-0532.

~~is less than 50%, it is expected that the distributor will provide supporting documentation outlining its role in the program.~~

~~By extension, should the distributor's role not meet the test of centrality, attribution should be determined between the parties and presented to the Board for approval at a time when it becomes relevant.~~

TRC benefits for program partnerships with Board rate-regulated entities such as electricity distributors should be allocated in the manner indicated in the Board's "Guidelines for Electricity Distributor Conservation and Demand Management". Where specific agreements have been developed by parties to deal with attribution for a program, these more case specific rules should be applied, so long as there is no double counting.

~~That is, a gas distributor partnering with an electricity distributor may claim all of the benefits associated with the gas savings in their franchise area. Other benefits, such as water savings, need to be allocated between the gas and electricity distributor partners proportionally based on the dollar value of gas and electric TRC savings (i.e., where gas savings represent 60% of the TRC savings of a program, the gas distributor will claim 60% of water savings).~~

2.5.3 Spillover ~~(New)~~

Spillover ~~is commonly defined as "~~addresses customers that adopt efficiency measures because they are influenced by [a distributor's] program-related information and marketing efforts, though they do not actually participate in the program~~"~~".[6] Due to these spillover customers in the distributor's franchise area, the distributor will lose revenue due to a lower demand for natural gas and the TRC savings could be underestimated. This in turn could affect the SSM claim.

~~A distributor that wishes the Board to consider spillover will need to provide comprehensive and convincing evidence that clearly quantifies the effect that spillover has had on program savings and the distributor's revenue.~~

Spillover is to be applied in a manner consistent with other TRC test adjustments. A distributor that wishes to include spillover should assess these impacts on the same basis as other input assumptions to the TRC Test (e.g. free ridership)..

Spillover is defined as:

> Spillover is comprised of energy savings that are due to the program but not counted in program records. Spillover is a combination of several factors that may influence non-reported actions to be taken at the project site itself (inside

[6] U.S. Department of Energy (2008). Understanding Cost Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy Makers.

spillover), at other sites by the participating customer or Energy Efficiency Contractors (outside spillover), or by non-participants (non-participant spillover). For example, a participating customer or Energy Efficiency Contractor might observe the benefits of installing efficiency measures at a program site and, based on this experience, install the same or similar measures at other sites without formally participating in the program. Spillover savings are added to the program's installed gross savings.

2.5.4 Persistence ~~(Changes Proposed)~~

Persistence is a measure of how long a DSM measure is kept in place by the customer. Persistence ~~is important for all energy efficiency programs as a lack of persistence can have very significant effects~~can have an effect on overall net program savings estimates, but can also be costly to measure. For example, if an energy efficient measure with a 15-year lifetime is removed after only two years, most of the savings expected to result from that installation will not materialize. For most common technologies such as furnaces and boilers, it is reasonable to assume that the equipment will not be removed from the building due to operational requirements.

~~As distributors have increased their experience in developing and evaluating DSM programs, there is a need for more thorough consideration of long-term retention, technical degradation, and persistence of savings in particular for programs with significant budgets and savings.~~ Distributors will be expected to ~~address~~consider persistence of savings in their next generation DSM plans and evaluations of programs. The potential accuracy gained by measuring persistence should be balanced against the costs involved.

2.6 Fuel Switching

Where fuel switching away from natural gas aligns with the distributor's DSM objectives, the distributor may pursue these activities.

Fuel switching to natural gas is not a DSM activity and DSM funds should not be used for this purpose.

2.7 Pilot Programs

A pilot program is one that involves the installation, testing or evaluation of technologies that are not already in use in Ontario, or in limited use, and that serves as a tentative model for future development. They can also test new delivery channel or marketing approaches to overcome barriers to market entry. Pilot program may be helpful for application to resource acquisition, market transformation or low income programs.

A properly structured pilot should provide an opportunity to gain experience in business processes, installation procedures, logistics, deployment, integration issues, customer communications, and customer impacts. A distributor should provide a rationale for how its program will increase the collective understanding of the technology and its benefits as a DSM measure. ~~Where the pilot program involves a non-cost effective technology, the onus will be on the distributor to prove the usefulness of the program~~Pilot programs that have a TRC ratio of less than 1.0 are detrimental to the utility resource acquisition SSM. Therefore, a utility will only pursue these initiatives where it is expected to generate positive TRC in future years. Utilities should be prepared to share the results and knowledge gained through the pilot with the Board and other utilities.

~~It is not considered appropriate to have distributors piloting the same technology or piloting technology that has already been deployed within the Province.~~

~~Therefore, where a technology is already being, or has been, installed, tested or evaluated by another distributor, a distributor that wishes to implement a pilot program using the technology will need to show how it will coordinate or work with the other distributor to ensure effective use of the program and of lessons learned.~~

3.0 DSM BUDGETS AND TARGETS ~~(CHANGES PROPOSED)~~

3.1 Budget Determination

In recognition of the knowledge and experience that the natural gas utilities have gained in developing and implementing DSM plans, distributors should propose a budget for their respective DSM plans. However, each distributor will need to justify its proposed DSM budgets based on:

- the results ~~of its DSM programs to date,~~anticipated from its proposed multi-year DSM plans, and,
- ~~the results of the program evaluation and market potential studies that it has completed, and~~
- the government's policies/initiatives in advancing conservation in Ontario.

Distributors should propose separate DSM budgets in the following program areas:

- Resource acquisition (TRC Net Savings)
- Market transformation
- Low income customers

Distributors are encouraged to consult with relevant stakeholders in developing their budgets for their DSM programs.

3.2 Budget Term and Reporting

There are benefits associated with multi-year funding for ongoing programs. Multi-year funding supports better planning and management and facilitates the utilities' entering into of partnerships with other delivery agents.

Distributors may therefore apply to the Board for multi-year DSM funding for up to 5 years. The term of the DSM budget will be the subject of a ~~rate~~Board proceeding where distributors and stakeholders will have the opportunity to provide their views to the Board.

When applying to the Board for funding, budgets, LRAM and SSM or other financial incentives they should be developed and measured on an annual basis (market transformation amounts may be an exception). Annual budget amounts will be an input to each year's distribution rate adjustment.

The application submitted to the Board should be in the form of a DSM plan, which includes a budget and an evaluation plan. The budget should include cost estimates for administration, evaluation, research (including market potential studies) and support.

~~Utilities should file annual reports, as described in section 9.0 below.~~

~~Spending will be tracked in a~~A DSM variance account~~, which will~~ should be used to "true-up" any variances between the spending estimate built into rates for the year and the actual spending in that year. If the Board has approved budgets with terms longer than one year, unspent funds can be carried over to a subsequent year. At the end of the approved funding term, any unspent funds will be returned to ratepayers through rates.

Where programs have been more successful than expected, such that the annual budget is insufficient, the distributor may ~~bring forward an application, with appropriate evidence and rationale, for recovery in rates of the amount spent in excess of the approved budget and tracked~~spend up to an additional 20% above the annual DSM budget as long as these funds are *used for incremental program* purposes. Such additional funding is usually required late in the program year and an immediate response is needed to avoid damaging successful momentum. Spending of these funds is to be recorded for clearance in the DSM variance account.

~~Consistent with the approach set out in the Board's August 25, 2006 decision on Phase I of the generic DSM proceeding:~~

- ~~Additional spending may only be *used for incremental program* expenses; and~~
- ~~At the time of its next cost-of-service application, the distributor must provide appropriate evidence demonstrating the prudence and cost effectiveness of the amounts spent in excess of the approved annual budget.~~

3.3 Adjustments to an Approved Plan

Utilities should evaluate the effectiveness of programs on an ongoing basis, and make adjustments as necessary to improve program design, performance, and uptake by customers. ~~Where cumulative fund transfers among Board-approved programs are less than 20% of the approved annual budget, no Board approval is necessary.~~Program factors such as the economy or other environmental factors can fluctuate within any given year. Flexibility during a program year has been a key factor for success for the natural gas utilities. If the multi-year DSM plan approved by the Board requires adjustments during the term, the utility should make an application for amendment to the Board. Experience from the previous Board approved multi-year plan has demonstrated that this scenario is very unlikely..

~~Utilities should apply for Board approval for cumulative fund transfers among programs that exceed 20% of the approved annual budget, as well as for approval to re-allocate funds to new programs that are not part of the distributor's approved DSM plan.~~

3.4 Targeted Program Spending

There is a tension between ensuring that each rate class is allocated an appropriate portion of DSM funds, on the one hand, and the benefits of targeting spending to the most cost effective programs regardless of what rate class they apply to, on the other. As a principle, DSM programs should provide customers in all rate classes and sectors with equitable access to DSM programs to the extent reasonable. This principle must be balanced against and consistent with the principle of optimizing cost-effective DSM opportunities.

If DSM sector (i.e., residential, commercial, or industrial) level spending is significantly different than the historical percentage levels of spending in those sectors, the distributor should provide its explanation for this in its proposed DSM plan. The Board will then determine whether to approve the revised spending ratios and, if so, under what conditions.

To the extent that actual sector level spending then varies significantly from the ratios identified in the plan, interested parties may challenge the appropriateness of the deviation from the plan when the distributor seeks approval for the clearance of the relevant accounts.

Market potential studies, or updates to an existing study, should be filed by each distributor together with its DSM plan. The distributor may, at its discretion, do additional studies of market potential or updates during its plan. The results of these studies could inform distributors in allocating DSM budgets among different sectors, rate classes, types of markets etc.

3.5 TRC Savings ~~Targets~~Metrics

~~TRC savings targets are designed to set goals for all of the savings achieved by a distributor's DSM activities. These targets are applicable to all DSM programs offered by a distributor excluding market transformation programs and DSM programs targeted to low-income customers. When evaluating the success of a distributor in reaching these targets, the distributor's DSM activities are assessed based on the net benefits accrued when utilizing the TRC test.~~

~~Distributors are expected to propose TRC savings targets based on the programs they plan to deliver over the next planning period.~~

Resource acquisition programs produce measurable results. The Total Resource Cost (TRC) test assesses the net benefits of DSM activities from a societal perspective. A shared savings mechanism provides for a sharing of DSM benefits between customers and the utility. It is expected that a fair and consistent sharing of benefits between ratepayers and the utility will incent the utility to optimize TRC benefits in the resource acquisition portfolio. TRC savings targets are not required in respect of resource acquisition programs.

3.6 Market Transformation ~~Targets~~Metrics

Market transformation programs are those that are designed to make a permanent change in the marketplace over a long period of time. ~~These programs tend to be more applicable to lost opportunity markets where, for example, equipment is being replaced or new buildings are being built~~In order to support Ontario's aggressive goals to grow the amount and diversity of renewable energy source, renewable energy initiatives that typically do not measure specific TRC may be included within Market Transformation.

Such programs are not amenable to a formulaic evaluation approach and therefore should be assessed on an individual basis using metrics which are suitable to a given program. Such metrics should be objective and able to measure success objectively, such as ~~increasing the~~activities undertaken, or changes in market share of a DSM technology. Depending on the program, other quantifiable metrics could include increase in consumer awareness due to an educational program and the like. Distributors are expected to propose specific metrics ~~and corresponding targets~~ for any proposed market transformation program.

For each market transformation program the utility should propose a program description, goals (including measurement method), shareholder financial incentives (including structure and payment), length, level of funding and program elements.

3.7 Low-income Customer Program ~~Targets (Changes Proposed)~~Metrics

Low-income customers face certain barriers in accessing DSM programs which are unique to this group of customers. In addition, the TRC net savings for these programs are typically low relative to the savings of other programs although very valuable for this market sector.

Targets for these programs could be based in part on TRC savings for these programs but also in part on other metrics such as market penetration of DSM programs in the low income segment of the population.

Distributors are expected to develop eligibility criteria and program parameters for low income residential programs. Criteria presently used by various levels of government for the purposes of determining eligibility for low-income consumer programs may be appropriate for use by distributors.

Distributors are also expected to propose explicit metrics ~~and corresponding targets~~ for the DSM programs targeted at low income consumers.

4.0 LOST REVENUE ADJUSTMENT MECHANISM (LRAM)

Unforecasted DSM results can have the effect of eroding distributor revenues due to lower than forecast throughput. Utilities recover fixed distribution costs through both a fixed and a variable rate, which is set based on a forecast of consumption, including natural changes in energy efficiency. If actual consumption is less than the forecasted amount used for rate-setting purposes, the distributor earns less revenue than it otherwise would have, all other things being equal. Since the intention and effect of DSM activities is to reduce natural gas use, it also has the effect of reducing throughput and associated distributor revenues, which can result in a disincentive for utilities to deliver DSM programs.

A mechanism to compensate for distributor-induced lost revenues is intended to remove the disincentive. LRAM is a retrospective adjustment, which is designed to recover revenues lost from distributor supported DSM activities in the prior year. It is designed to compensate a distributor only for unforecasted lost revenues associated with DSM activities undertaken by the distributor within its franchise area.

4.1 Eligible Programs

The LRAM applies to programs implemented by the distributor, within its franchise area, including programs delivered by the distributor itself and/or programs delivered for the distributor by a third party (under contract with the distributor).

Distributors may undertake some programs in partnership with other entities, such as electricity distributors or community agencies. In assessing the distributor's involvement in program delivery, and the resulting potential impacts on revenue, distributors should be guided by section 2.5.2 regarding the attribution of benefits. ~~Distributors may only recover LRAM for revenue losses that can be attributed to the distributor's involvement in the program.~~

4.2 Calculation of LRAM

The LRAM is determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class. Lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time. The first year impact will be calculated as 50% of the annual fully effective volumetric impact multiplied by the distribution rate for each of the rate classes that the volumetric variance occurred in.

~~The LRAM mechanism will be calculated using the assumptions and savings estimates approved in the plan and adjusted for the audited Evaluation Report (see section 6.4) results, and will apply from the beginning of the year being audited. The LRAM account discussed in section 4.3 will be cleared annually. LRAM will be recovered in rates on the same basis as the lost revenues were experienced so that the LRAM ends up being a full true-up by rate class. Assumptions used should be best available at the time of an audit.~~

~~LRAM amounts to be recovered in rates should be adjusted for free riders. As noted above, free riders are those customers who would have adopted or installed an energy efficiency measures regardless of the involvement of the distributor. This is often called natural conservation. Given that the LRAM is intended to compensate utilities for revenue losses resulting from the distributor having implemented a DSM program, the LRAM should be adjusted to remove the free riders. Similarly, LRAM should be adjusted for spillover effects to the extent they can be empirically estimated.~~

As indicated by the filing guidelines set out in section 10.1, utilities should include in the application for recovery of LRAM the volumetric impact of measures and programs implemented in a specific year. Volumetric savings, costs of programs, free riders and other adjustments, as discussed above, should be based on the results of the evaluation and audit work completed for the year for which LRAM is applied. The impacts should be calculated for each program and for each class both gross and net of free riders. The amount to be recovered through rates will be determined as net of free riders and spillover effects.

By way of example, if in June of 2008 the audit of the 2007 programs is completed and demonstrates a change in assumptions, that change will apply for LRAM purposes from the beginning of 2007 onwards until changed again. Best available information for the purposes of LRAM is that information available to the distributor immediately prior to the commencement of the audit by the independent third party.

Utilities will be expected to file an audit report and any back up program evaluation reports needed to support the volumes used in the LRAM calculation. The audit report should be prepared by an independent auditor and provide an opinion on the LRAM proposed and any necessary amendment thereto.

4.3 Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)

The purpose of the LRAMVA is to record the amount of distribution margin gained or lost when the distributor's DSM programs are less or more successful than budgeted. When the distributor's DSM programs are less successful in the test year than budgeted, the distributor gains distribution margin. Similarly, the distributor loses distribution margin in the test year when its DSM programs are more successful than budgeted.

4.4 Timing of LRAM Application

An application to clear the balance in the LRAM variance account, together with carrying charges, should be made on an annual basis. ~~As discussed above, for purposes of clearing LRAM, input assumptions will be adjusted on an annual basis, as a result of the evaluation and audit work completed and should apply for the beginning of the year being completed.~~

5.0 INCENTIVE PAYMENT MECHANISMS ~~(CHANGES PROPOSED)~~

LRAMs remove a disincentive for utilities to implement DSM, but do not provide an incentive for utilities to ~~aggressively~~successfully implement DSM programs. Given a certain level of resources, the distributor should make a trade-off between pursuing a DSM activity versus other activities.

Shareholder incentives are an appropriate way to encourage utilities to successfully pursue DSM programs.

5.1 Eligible Programs

The SSM and other financial incentives are available for customer focused initiatives that are funded through distribution rates and where the costs of the initiatives are expensed, such as efficiency improvements in the use of natural gas. The SSM and other financial incentives are not available for distributor-side expenditures or programs that are not funded through distribution rates.

Utilities may undertake some programs in partnership with other entities, such as electricity distributors or community agencies. In assessing the distributor's involvement in program delivery, utilities should be guided by the guidelines set out in section 2.5.2, regarding the attribution of benefits. A distributor may only claim a shareholder incentive in relation to its contribution to the program, as determined by the attribution guidelines.

Distributors can apply for separate incentives for the following types of programs:

- SSM for Resource Acquisition Programs (TRC Net Savings)
- Market Transformation Programs
- Low Income Programs

The SSM and other financial incentives are pre-tax amounts. In addition, the SSM should be calculated across the entire portfolio of DSM programs (excluding market transformation and low-income programs), including any programs with negative benefits.

The amount of any SSM and other financial incentives should not be included in the distributor's return on equity for the purposes of setting rates or in the calculation of any earnings sharing amounts.

5.1.1 Shared Savings Mechanism (SSM) for Resource Acquisition Programs

For SSM purposes, distributors should calculate the TRC net benefits of the DSM programs, and adjusting for free riders and spillover effects as required. The TRC savings from low income programs and market transformation programs should be excluded from this calculation since there is a separate incentive mechanism for low income customer programs as discussed in section 5.1.3 below.

~~The~~To provide a consistent, fair and effective reward structure~~ will continue to be~~, the ~~non-~~linear function relative to TRC savings as ~~decided in the DSM generic proceeding.Distributors are expected to propose annual financial incentive targets relative to the TRC savings targets they expect to achieve as a result of the programs they plan to deliver over the next planning period~~approved by the Board should be used. . This provides a transparent and straightforward incentive that will enable the distributor to balance DSM with other business objectives.

Regarding allocation of SSM costs among customer classes, DSM shareholder incentive amounts should be allocated to the rate classes in proportion to the net TRC benefits attributable to the respective rate classes.

~~For the purposes of determining whether each distributor has met its TRC target, the input assumptions for the calculation of SSM should be based on the best available information at the time of evaluation, similar to LRAM adjustments. The utilities have had several years of experience to conduct evaluation studies and make major changes to the input assumptions and as a result there is no need to lock-in the input assumptions from the year before~~The rules for calculation of TRC results for SSM purposes have been an important factor for driving utility activities over the past decade. These rules have been continuously approved by the Board over time, including in the most recent DSM Generic Hearing (EB-2006-0021). Assumptions used from the beginning of any year will be those assumptions in existence in the immediately prior year, adjusted for any changes in the audit of that prior year. By way of example, if in June of ~~2009~~2008 the~~ evaluation or~~ audit of the ~~2008~~2007 programs demonstrates a change in assumptions, that change shall apply for SSM purposes from the beginning of 2008 onwards until changed again.".

The Board has spent considerable resources having Navigant Consulting Inc. update the measures assumption list. The Board approved measures list will provide distributors the certainty they need to make the necessary business decisions to pursue successful DSM.

5.1.2 Market Transformation Incentive

For market transformation programs, a utility could be entitled to an incentive payment ~~up to a certain amount each year~~ based on the measured success of the programs relative to the established ~~targets~~metrics discussed in section 3.6 above. This amount will be in addition to any amount earned as SSM discussed in section 5.1.1 above.

Incentive payments for market transformation programs should be made on an individual program basis. ~~Distributors are expected to use a program's approved evaluation metrics to determine the program's success relative to the established targets.~~ The incentive payment will be tied to the ability of the program to ~~meet~~deliver (or surpass) ~~its established targets.~~the defined metrics.

The measurement and calculation methodologies to be used to determine whether the incentive has been earned in a year should be detailed by each distributor in its DSM plan.

5.1.3 Low Income Customer Programs Incentive

Incentive payments for low-income customer programs may be made on an individual program basis. This incentive will be in addition to any amount earned as SSM discussed in section 5.1.1 above.

Distributors are expected to use the program's approved evaluation metrics to determine the program's success relative to the established ~~targets~~metrics discussed in section 3.7 above. The incentive payment will be tied to the ability of the program to meet (or surpass) its established targets.

The measurement and calculation methodologies to be used to determine whether the incentive has been earned in a year should be detailed by each distributor in its DSM plan.

5.2 Shared Savings Mechanism Variance Account (SSMVA)

The purpose of the SSMVA is to record the amount of the shareholder incentive earned by the distributor as a result of its DSM programs. The SSMVA account should include incentives earned from distributors from Resource Acquisition Programs (TRC Net Savings), Market Transformation Programs and Low Income Customer Programs.

The balance of this account, together with carrying charges, will be disposed annually.

5.3 Timing of Application

Distributors should apply for SSM and other financial incentives annually. ~~As discussed above, for purposes of calculating SSM and other financial incentives, input assumptions will be adjusted on an annual basis based on the results of the evaluation and audit work completed and should apply for the beginning of the year being~~

~~completed~~Section 2.1.12 of the Natural Gas Reporting & Record Keeping Requirements (RRR) Rule for Gas Utilities includes the timing requirements for annual audited DSM results.

6.0 PROGRAM EVALUATION AND AUDIT

Effective monitoring, evaluation, verification and reporting of DSM program outcomes is a critical part of ensuring that programs are cost effective, generating the desired outcomes, and providing real savings to consumers. Evaluation also provides utilities with the future opportunity to identify ways in which a program can be changed or refined for greater efficiency in delivery and cost effectiveness.

Utilities should undertake evaluations of programs funded through distribution rates. The evaluation of DSM activities is important to support the Board's review and approval of LRAM, SSM and other financial incentive claims made by utilities.

Evaluation of the energy savings of a program is needed to determine the impact on a distributor's revenues as a result of reduced throughput.

The California Evaluation Framework identifies two key functions of evaluation:

1) To document and measure the effects of a program ~~-~~ = "Summative Evaluations."

2) To help understand why those effects occurred and identify ways to improve the program ~~-~~ = "Formative Evaluations."

The first function represents a threshold for assuring accountability for the expenditure of resources on that program. Evaluation activities are done after the program has been operating and focus on documenting impacts with a view to informing decisions regarding continuation, expansion or cancellation of the program. Formative evaluations (often referred to as process evaluations) may be done earlier in a program's continuum and focus on providing feedback regarding the operational effectiveness of a program. The results of the evaluation serve to inform decisions regarding mechanisms to improve the program.

A key tenet of good program evaluation practices is the identification of the evaluation activities as part of the initial program design. This ensures that the operational characteristics of the program generate the data and information that can assist in the program evaluation. This can be as simple as collecting relevant contact information as part of the operation of the program which will be used in follow-up activities, or more complicated activities such as pre and post implementation metering of equipment. In both cases, the evaluation techniques and parameters are integrated with the design and operation of the program.

It is incumbent on utilities to attempt to improve their programming capabilities over time. This may involve re-visiting the programs from time to time through the use of process evaluations that examine the effectiveness of the delivery. All programs should consider a certain level of process evaluation effort at some point. Typically, process evaluations occur earlier in a program's life rather than later ~~-~~ – i.e., early enough to revise the program as a result of the evaluation. This will vary based upon the size and nature of the programs, where they are in their life, and the similarity (or lack of similarity) to other distributor programs. For small programs, the evaluation effort could focus on secondary research augmented by interviews with key personnel involved in the program. Larger programs might involve greater depth of evaluation including market research, surveys with participants and non-participants and related primary research activities. In the end, the intent is to ensure that programs operate at the highest level of effectiveness and that the process evaluation results are made available to other utilities to assist them in their delivery.

6.1 Evaluation Plan

An overarching element of effective evaluation is the need to identify, at the outset, how each program will be evaluated. ~~This establishes both the individual metrics that will be measured/tracked and evaluated and the mechanisms that will be used. It further ensures that the evaluation effort is adequately contemplated and resourced.~~

~~Utilities should file an Evaluation Plan along with the application for funding for any program(s). Approval of the distributor's DSM plan will be conditional upon approval of an acceptable Evaluation Plan for the program(s) contained in the DSM plan.~~The purpose of the Evaluation Plan will be to identify the key evaluation metrics, activities and outcomes associated with each of the distributor's DSM programs.

It is recognized that not all programs will need an evaluation effort in each year.

However, at a minimum the distributor should anticipate and plan for a certain level of evaluation activities over the continuum of a program's life.

In addition to meeting the evaluation objectives listed below, any Evaluation Plan should include the distributor's proposed methodology for:

- ~~Measuring~~Assessing program effects (summative evaluation); and,
- Assessing why effects occurred, and how the program can be improved (formative or process evaluation).

The Evaluation Plan(s) should outline how the distributor will accomplish the following evaluation objectives:

- ~~Measuring~~Assessing the level of natural gas savings achieved;
- ~~Measuring~~Assessing cost-effectiveness;
- Informing decisions regarding LRAM, SSM and other financial incentive amounts;
- Providing ongoing feedback, and corrective and constructive guidance regarding the implementation of programs; and
- Helping to assess whether there is a continuing need for the program.

6.2 Program Type Specific Guidelines

This section focuses on the guidelines, in addition to those set out above, for tracking and measuring the effects of the following five types of DSM programs:

Direct acquisition programs are programs that have clear causality between distributor activity and natural gas and other resource savings.

Market support/outreach programs are programs in which the distributor supports outreach or educational efforts which generally promote the energy efficiency message, but where savings are indirect and it is difficult to see a clear cause and effect relationship.

Custom projects are those projects that involve customized design and engineering, and where a distributor facilitates the implementation of specialized equipment and technology that is not identified in the list of inputs and assumptions posted on the Board's website.

Market transformation programs are those that (a) seek to make a permanent change in the market for a particular measure, (b) are not necessarily measured by number of participants and (c) have a long term horizon.

Low income customer programs are those that are specially designed to reduce the natural gas consumption of low income customers.

6.2.1 Direct Acquisition Programs

Direct acquisition programs are relatively straightforward to track and measure. Tracking represents one of the administrative functions of program delivery. While the specifics will vary for each type of program, there is a need to show clear cause and effect between the distributor's activities and the customer's reduction of natural gas consumption. In direct acquisition programs, this is often precipitated by the processing of a participant incentive. Utilities will need to have systems for collecting relevant information for each program, including:

- technology type;
- number of installations;
- savings estimates;
- equipment cost estimates;
- customer address or location;
- delivery channel; and
- participant incentive amount.

It may not be feasible to collect all information for all programs. For example, a program delivered by a retailer that relies on in-store coupons will likely not have the means to track who actually used the coupons and received the product(s). However, the retailer can be expected to track information about the number of coupons turned in, and the distributor’s tracking system could then calculate the resulting cost to the distributor. With this information, the distributor can then calculate the savings and equipment cost and combine the information with equipment life, free rider and spillover estimates and program costs - resulting in both a tracking report and the components of the TRC analysis.

In the case of a program delivered by a third party, tracking should include reports that the delivery partner provides to the distributor. These reports should provide details such as number of customers visited including address and equipment installed.

6.2.2 Market Support Programs

Natural gas savings from DSM activities related to training, public outreach and the general provision of information on efficient energy use are difficult to track, measure and establish clear causality. Since market support programs typically do not result in natural gas savings, other assessment criteria should be used to assess their benefits. A distributor should endeavour to have at least one metric for each market support activity.

Below is a sample of potential tracking activities that might accompany the delivery of market support program.

Support	Metric	Additional Information
Web-site calculator	Number of hits	Survey re: usefulness of website
Training sessions for contractors	Number of sessions Number of attendees	Survey re: specific activities undertaken by attendees
Home shows	Number of giveaways	Survey re: energy efficient appliances
Design workshops	Number of professional attendees	Surveys re: design activities

6.2.3 Custom Projects

Custom projects are those projects that involve customized design and engineering, and where a distributor facilitates the implementation of specialized equipment or technology not identified in the list of inputs and assumptions as posted on the Board’s website. Projects that involve a combination of several measures provided in that list of inputs and assumptions are not considered to be custom projects.

For a custom project, utilities will need to track:

- the type of equipment that was installed;
- the related savings and equipment cost; and

- distributor support costs.

Since custom projects usually involve specialized equipment, savings estimates should be assessed accordingly. It is expected that ~~each~~ custom ~~project~~projects will incorporate ~~a~~ professional ~~engineering~~project specific assessment of the savings. This assessment would serve as the primary documentation for a claim that savings exist. ~~Assumptions with respect to measure life should reflect actual expected measure life.~~

A special assessment program should be implemented for the evaluation of custom projects. The assessment should be conducted on a random sample consisting of 10% of the large custom projects; and the projects should represent at least 10% of the total volume savings of all custom projects. The minimum number of projects to assess should be 5. Where less than 5 custom projects have been undertaken, all projects should be assessed. The assessment should focus on verifying the equipment installation and estimates of savings and equipment cost.

Custom projects should be audited using the same principles as any other program. Audit activities should be sufficient for the auditor to form an opinion on the overall LRAM, SSM and other financial incentives proposed in the Evaluation Report~~. As noted earlier, only the part of the project that the distributor influenced is to be counted for SSM or LRAM purposes~~.

6.2.4 Market Transformation Programs

For each market transformation program the distributor should, in its DSM plan, propose a program description, goals (including specific metrics and measurement method), shareholder financial incentives (including structure and payment based on specific metrics), length, level of funding and program elements. Such programs are not amenable to a formulaic approach and therefore should be assessed on their own merits and all of the above components should be suitable given the subject matter and program goals.

6.2.5 Low Income Customer Programs

For each low income customer program the distributor should, in its DSM plan, propose a program description, goals (including specific metrics and measurement method), eligibility criteria, shareholder financial incentives (including structure and payment based on specific metrics), length, level of funding and program elements.

6.3 Implementation of Updated Input Assumptions

The input assumptions used to screen DSM technologies and programs may change over time due to more accurate and up-to-date information. The timing at which changes in assumptions become effective will differ depending on the use of the assumption, as follows:

Program Design and Implementation

Utilities should design, screen and evaluate programs using the best available information known to them at the relevant time. Therefore, it is expected that utilities will incorporate new information into program design and implementation as soon as available. In considering the prudence of any spending in excess of an approved budget that has been tracked in a DSM variance account, it is expected that the information available to the distributor at the time the program was implemented will be considered. That is, when amounts in a DSM variance account are being reviewed for the purposes of disposition, it is expected that the information available to the distributor at the time the spending decision was made by the distributor will be considered. This will apply even if the input assumptions have changed since that time.

SSM

The distributor should use the Board approved Input Assumptions for calculation of TRC for SSM purposes. This provides distributors the certainty needed to make prudent business decisions without having the goalposts moved after the fact. Assumptions used from the beginning of any year will be those assumptions in existence in the immediately prior year, adjusted for any changes in the audit of that prior year. By way of example, if in June of 2008 the audit of the 2007 programs demonstrates a change in assumptions, that change shall apply for SSM purposes from the beginning of 2008 onwards until changed again

LRAM~~, SSM and Other Financial Incentives~~

The input assumptions used for the calculation of LRAM~~, SSM and other financial incentives~~ should be the best available at the time of the independent third party review referred to in section 6.5 below.

For example, if any input assumptions change in any given year, those changes should apply for LRAM ~~and SSM~~ purposes from the beginning of that year onwards until changed again.

Assume a program was delivered from January 1, 2007 until December 31, 2007. In June 2007, it was determined that the free rider rate used in the initial program analysis was under-stated. The distributor obtains a third party review of its evaluation of program results in April 2008. The input assumptions that will apply in relation to any lost revenue between January 1, 2007 and December 31, 2007, will be those that were introduced in June 2007. That is, the new free rider rates apply for the entire period from January 1, 2007 to December 31, 2007.

Best available information for the purposes of LRAM is that information available to the distributor immediately prior to the commencement of the audit by the independent third party.

6.4 Evaluation Report

A distributor that makes an LRAM, SSM or other financial incentive claim will need to file a detailed Evaluation Report at the time of making that claim. The Evaluation

Report should consist of the following sections:

Introduction

In the "Introduction" section of the Evaluation Report, utilities should provide a general overview of their DSM initiatives including any relevant local context.

Evaluation of the DSM Plan

This section should provide an overview of the effectiveness of a distributor's DSM plan. Utilities should report on all initiatives worked on and detail the process and impact analysis of the individual programs.

Note:

Stand alone education or marketing programs that do not have quantifiable benefits should report all relevant information (potential assessment criteria are identified in section 6.2.2). Marketing or support programs (i.e., programs designed to enhance market acceptance of other programs) should not be reported individually as they are components of other programs. Rather, the costs of marketing or support programs should be allocated to the programs they support.

Utilities who have pilot programs (see section 2.6), or other programs for which cost effectiveness data has not been provided by the Board (on the Board's website) should provide their own values, if available, and report all relevant information (attach a separate table if needed).

If the inputs and assumptions used by the distributor vary from those that have been posted on the Board's website, the variation(s) should be identified, and additional information supporting the variation(s) should be filed. If the specific technology promoted by a distributor was not included by the Board (on the Board's website), the distributor may select a similar technology as a proxy for annual reporting purposes. A distributor that selects a proxy technology for reporting should identify the actual technology in its Evaluation Report and the similarities between the proxy technology and the actual technology. However, for the purposes of a claim for recovery of LRAM, SSM or other financial incentives, where a distributor uses a proxy technology, the distributor should provide detailed evidence justifying the appropriateness of using the proxy technology, and detail the steps the distributor has taken, or will take, to determine the actual data for the technology used in the DSM program.

Lessons Learned

In the “Lessons Learned” section the distributor should indicate what has been learned over the course of the program. The goal of this section is to evaluate and benchmark programs for greater efficiency in delivery and cost effectiveness, and to provide information to other utilities with respect to DSM programs. Utilities should indicate if a program is considered a success or not and whether the program should be continued.

(4) Conclusion

The “Conclusion” section should consist of the distributor’s summary of its performance relative to the DSM plan approved by the Board.

6.5 Independent Third Party Review

Given the rate-making implications of program evaluations, the Board and all relevant stakeholders need to be confident that evaluations are an accurate reflection of actual program results.

~~Utilities should undertake program evaluations according to the approved Evaluation Plans, and have the evaluations reviewed by an independent third party engaged by the distributor for the purposes of LRAM, SSM and other financial incentive claims filed with the Board.~~

Section 2.1.12 of the Natural Gas Reporting & Record Keeping Requirements (RRR) Rule for Gas Utilities includes the timing requirements for annual audited DSM results.

The third party, although hired by the distributor, should be independent and will ultimately serve to protect the interests of ratepayers. Utilities should ensure that DSM budgets and spending include adequate funding to procure the third party review.

The third party is expected to:

- Provide an opinion on the cost effectiveness results that are material to the LRAM, SSM and other financial incentives proposed;
- ~~Confirm that the utilities have undertaken program evaluations according to the approved Evaluation Plans.~~
- ~~Review the evaluation reports and ensure that the distributor has used the most recent results from program evaluations.~~

- Verify the ~~participation levels;~~results in the Evaluation Report to the extent necessary to give that opinion

- Confirm that ~~the~~ the Board Approved input assumptions ~~are those that~~ have been ~~posted on the Board's website~~used. Where any input assumptions ~~have changed in previous years, confirm that the input assumptions were implemented consistent with section 6.3~~not on the Board approved list were used, provide an opinion on reasonableness of the assumption;

- Where the distributor has varied from the Board approved input assumptions ~~that have been posted on the Board's website~~, review the reasonableness of the input assumptions used;

- Recommend any forward looking evaluation work to be considered; and

- Recommend any ~~improvements to the program to enhance program design, performance, and uptake by customers~~relevant program improvement suggestions.

7.0 DSM CONSULTATIVE

Distributors should engage and seek advice from a variety of stakeholders and experts in the development and operation of their DSM programs as they consider appropriate. Given that the distributor can benefit by generating more TRC from its program portfolio, there is a natural interest to solicit input from those stakeholders that may bring value to the DSM program portfolio.

~~However, it~~It is expected that each distributor will hold, at a minimum, two DSM Consultative meetings annually. All intervenors in the distributor's most recent rate case should be invited to participate in these DSM Consultative meetings. The purpose of the meetings should be to:

- Review annual results (the Evaluation Report should be sent to the Consultative annually for review)

- Select an Evaluation and Audit Committee (EAC). Three members should be selected using the current process for selecting the Audit Sub-Committee; the fourth member will be the distributor. In the current process, the members of the consultative nominate individuals to stand on the committee. Then each member of the consultative votes for the three members they would like on the committee. The three members with the highest number of votes are selected to the committee.

- Review the completed evaluation results

The EAC should provide formal input into the distributor's Evaluation Plan. In regards to evaluation activities, the EAC should have an advisory role in relation to the matters listed below:

- Consultation prior to the filing of the DSM plan on evaluation priorities over the lifetime of the plan
- Review and comment on evaluation study designs.
- Reviewing the scope and results of evaluation work completed on new programs introduced over the course of the DSM plan
- Selection of the independent auditor to audit the Evaluation Report and determine the scope of the audit. The EAC should ensure that all comments on the Evaluation Report that arise from the DSM Consultative meetings are reviewed by the auditor.
- Following the audit, review the ~~Evaluation Plan~~evaluation plan annually to ~~confirm~~advise the Company on the scope and priority of identified evaluation projects.
- ~~The EAC should also be involved in the preparation of the distributor's filing under section 2.1.12 of the Natural Gas Reporting & Record Keeping Requirements Rule for Gas Utilities. The EAC should provide a final report within 10 weeks from the date of receipt of the Evaluation Report and supporting evaluation studies from the utility or the date of hiring of the auditor, whichever is later. Recommendations of the EAC with respect to DSMVA, LRAMVA and SSMVA clearances should be included in the EAC's final report.~~

Distributors, in consultation with the DSM Consultative, are expected to develop clear terms of reference regarding the role and operation of the DSM Consultative and EAC.

The distributor should determine, as part of the planning process, the appropriate amount to include in its overall DSM budget for stakeholder engagement, based on anticipated needs.

8.0 ACCOUNTING TREATMENT

8.1 Funding of DSM Programs

There could be two potential streams of funding available to distributors for the delivery of DSM programs: funding through distribution rates and funding from third parties.

Should an alternative source of funding become available for a program which was funded through distribution rates, the distributor should apply for that funding. In such circumstances, the DSM variance account should track the funding which was originally included in the distribution rates, so that it may be returned to ratepayers~~. Alternatively, a distributor may apply to the Board to use the funding for another DSM program~~.

8.2 Cost Allocation

Utilities should use a fully allocated costing methodology for all ~~distributor-delivered~~third party funded DSM activities. Capitalized assets associated with DSM activities that are funded through rates will be included in rate base, and will be treated in the same manner as distribution assets. Assets purchased with funds from third parties will not be eligible for inclusion in rate base, nor will any ongoing operating costs associated with the asset, or income taxes payable in relation to third-party funded activities. The accounting treatment of DSM spending not funded through distribution rates is discussed in section 8.6 below.

Where funding is coming from a third party, the separation in costs will appropriately establish distribution rates by eliminating any cross subsidization between third-party funded DSM activities, and those activities funded through distribution rates. Where the funding would be from the distributor's rates, ~~fully allocated~~marginal costing will ensure that there is an appropriate basis to determine the cost effectiveness of DSM programs.

Cost allocation in rates should be on the same basis as budgeted DSM spending by customer class. This allocation applies to both direct and indirect DSM program costs.

8.3 Revenue Allocation

Any net revenues generated by a shareholder incentive for distribution rate~~-~~-funded DSM should be separate from (i.e., not used to offset) the distributor's distribution revenue requirement.

Revenue earned from undertaking DSM funded by a third party shall also be treated on a fully allocated basis and separately from distribution revenues generated from ratepayer funded initiatives.

8.4 Demand Side Management Variance Account (DSMVA)

The rules around the DSMVA are as outlined in Section 3.2.

The distributor should apply annually to clear DSMVA amounts, subject to review as a component of the DSM audit, to ensure compliance with the Board approved rules. ~~The distributor should include the DSMVA as part of the mandated audit. The distributor will be permitted to recover the amounts in the DSMVA from ratepayers provided it has achieved its annual TRC savings or other targets on a pre-audited basis and the DSMVA funds were used to produce TRC savings in excess of that target on a pre-audited basis~~.

Utilities should allocate the DSMVA amounts in rates based on their DSM spending variance for that year versus budget, by customer class. The actual amount of the variance versus budget targeted to each customer class should be allocated to that customer class for rate recovery purposes.

~~If spending is less than what was built into rates, ratepayers should be reimbursed. If more is spent than was built into rates, the distributor should be reimbursed up to a maximum of 15% of its DSM budget for the year. All additional funding should be utilized on incremental program expenses only (i.e., cannot be used for additional distributor overheads).~~

~~There should be no limit on the amount of under spending from budget that should be returned to ratepayers.~~

8.5 Carbon Dioxide Offset Credits Deferral Account (CDOCDA)

The ~~purpose of the CDOCDA is~~CDOCDA was introduced by the OEB in the Generic Hearing and was developed to record amounts which represent proceeds resulting from the sale of or other dealings in earned carbon dioxide offset credits. There have not been any entries in this account since its inception. Now is the time to provide an incentive to distributors to create business opportunities to help customers manage carbon dioxide emissions.

Based on the right business incentives, distributors may have the ability to develop business offerings to work with customers to manage emission commitments. The CDOCDA is to be removed in order to provide distributors an opportunity to make this a profitable part of their business. This is consistent with the incentive regulation principle of minimizing deferral accounts. Through the current incentive regulation earning sharing mechanism, there is an inherent opportunity for ratepayers to benefits from this business opportunity should it become successful.

8.6 Recording of DSM Spending Not Funded Through Distribution Rates

Third-party funded DSM programs are classified as non-distribution activities. Consequently, the financial records associated with third-party funded DSM should be separate from those associated with the distributor’s distribution activities.

A distributor receiving third-party DSM revenues and incurring related DSM expenses and/or capital expenditures should record these transactions in separate non-distribution accounts in the Uniform System of Accounts for Gas Utilities. For this purpose, account 312, Non-Gas Operating Revenue, should be used for revenues and account 313, Non-Gas Operating Expense, should be used for expenses. Sub-accounts may be used as appropriate.

9.0 ANNUAL REPORTING GUIDELINES ~~(NEW)~~

The guidelines set out in this section relate only to DSM programs funded through distribution rates.

Reporting on the progress and success of DSM programs is critical to maintaining accountability and transparency. For programs funded through distribution rates, utilities should file annual reports, by June 30 of each year as required by section 2.1.12 of the Natural Gas Reporting & Record Keeping Requirements Rule for Gas Utilities. Where utilities have approved funding for more than one year, a report should be filed annually summarizing the results of the previous year, and at the end of the plan term, addressing results for the entire plan term.

If the Board has approved DSM plans that span more than one year, annual reporting will be an important tool to allow the Board and stakeholders to monitor utilities' year-over-year progress in the implementation of their DSM plans. The annual report should provide the Board and stakeholders with information on what DSM activities the distributor is undertaking, how it is performing, what it is costing, and the distributor's planned future activities.

Where utilities have separate streams of funding, results should be differentiated in the Annual Report.

The Annual Report should consist of the following sections:

1. ~~1.~~ Introduction

In the "Introduction" section of the annual report, utilities should provide a general overview of their DSM initiatives including any relevant local context.

2. ~~2.~~ Description of the programs

In this section, the distributor should provide an overview of each program, including the targeted customer class or group, the objectives of the program, and any activities associated with the program.

3. ~~3.~~ Participation levels

In this section, distributors should detail the number of participants for each program.

4. ~~4.~~ Natural Gas savings in M^3

In this section, distributors should provide the annual and cumulative energy savings attributable to each program, presented as both net and gross of free riders.

5. ~~5.~~ Measures evaluation research

In this section, distributors should describe any research completed regarding deemed savings assumptions and free rider and spillover estimates. The completed studies should be included as an appendix to the Annual Report.

6. ~~6.~~ LRAM statement

In this section, distributors should provide a statement that outlines the expected LRAM claim for the year of the Annual Report.

7. ~~7.~~ SSM and other incentives statement

In this section, distributors should provide a statement that outlines the expected SSM and other incentive claims for the year of the Annual Report.

8. ~~8.~~ Comments

In this section, distributors should provide any additional information as appropriate. This may include the distributor’s assessment of the success of the programs to date, what activities are planned for the subsequent year(s) (if applicable) and any planned modifications to program design or delivery.

10.0 ADMINISTRATION

10.1 Filing Guidelines (New)

This section contains the filing guidelines for the following types of applications:

10.1.1 - Program funding through distribution rates
10.1.2 - Lost Revenue Adjustment Mechanism
10.1.3 - Shared Savings Mechanism and other financial incentives
10.1.4 - Adjustments to an approved DSM plan

It is expected that utilities will comply with these filing guidelines as a minimum. Utilities should in all cases be prepared to demonstrate to the satisfaction of the Board that any given application should be approved, and are responsible for ensuring to that end that all relevant information is before the Board (including evidence that may have been filed in an earlier proceeding). Utilities are reminded that the Board may make any order or given any direction as the Board determines necessary concerning any matter raised in relation to any of the above applications, including in relation to the production of additional information which the Board on its own motion or at the request of a party considers appropriate.

10.1.1 Program Funding through Distribution Rates

An application for funding through distribution rates for new programs should include:

1. ~~1.~~ Characteristics of the applicant’s distribution system, including:

- Total natural gas purchases;
- Sales by rate class; and
- Number of customers by rate class.

2. ~~2.~~ For each program, the following information should be provided:

- Detailed description of the program;
- Customer ~~c1ass~~class(es) targeted;
- Projected incremental natural gas savings per year;
- Projected budget, listing:
- Description of the primary barriers to preventing higher uptake of the measures of the program
- Description of how the program will remove the barriers;

    - capital expenditures per year;
    - operating expenditures per year separated into direct and indirect expenditures;
    - for each direct operating expenditure, an allocation of the expenditure by targeted customer classes; and
    - expenditures for evaluation of the program(s).

- Measure, programs and portfolio cost effectiveness results;

- The input assumptions underlying the forecasted savings and costs including a detailed presentation of the calculations;

- Where a program involves the implementation of specialized equipment or technology not identified in the list of inputs and assumptions as posted on the Board's website, the distributor should comply with the guidelines set out in 6.2.3 respecting custom projects;

- A statement as to whether the distributor has varied from the list of inputs and assumptions as posted on the Board's website. Where the distributor has varied from that list of inputs and assumptions, the distributor should provide detailed evidence to support the alternative data, including, at a minimum, a completed "Input Assumptions Template"; and

- The benefit-cost analysis, calculating the net present value of the initiative using the TRC test. For the purpose of calculating the net present value, a distributor should use a discount rate equal to the incremental after-tax cost of capital, based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity.

3. ~~3.~~ **The distributor should also provide the following (specified on a per year basis):**

- The total amount of DSM spending to be recovered in rates and the allocation of those costs to the customer ~~c1ass~~class(es) that will benefit from the DSM program applied for;

- A forecast of the number of customers in each class and a forecast of M~~3~~• of natural gas to be used as a charge determinant to determine the rate rider for each class to benefit from the DSM program; and
- A comparison of the proposed rates with and without the DSM rider for the rate year in question.

4. ~~4.~~ **An Evaluation Plan, in accordance with section 6.1.**

5. ~~5.~~ **In addition to the information above, the following information should be provided for pilot programs (see section 2.6):**

- A description of the technology being used;
- A discussion of whether and how, to the distributor's knowledge, the technology is being used or tested by any other utilities. Where the technology is being used by another distributor, a description of how the distributor will coordinate or work with the other distributor using or testing the technology to ensure effective use of the program and of lessons learned; and
- The expected outcome of the pilot program. That is, what data or information will the program produce, and how will it be used for future DSM programs.

10.1.2 Lost Revenue Adjustment Mechanism (LRAM)

Section 4.0 contains information on the programs that are eligible for LRAM, the calculation of LRAM, and the timing of any application for recovery of LRAM.

An application for LRAM should include:

Third-Party Funded Programs

- Natural gas savings (both gross and net of free riders) for each program and for each class;
- The free rider rate applied to each program. Where different activities within a program have different free rider rates, the free rider rate for each activity should be provided;
- A calculation of the impact of the DSM program on distribution revenues in each class;
- Verification of the participation levels;
- Duration of the program in years or months;
- An Evaluation Report, in accordance with the guidelines set out in section 6.4; and
- Any reports completed by an independent third party, in accordance with the guidelines set out in section 6.5.

Programs Funded through Distribution Rates

- Natural gas savings (both gross and net of free riders) for each program and for each class;
- The free rider rate applied to each program. Where different activities within a program have different free rider rates, the free rider rate for each activity should be provided;
- A calculation of the impact of the DSM program on distribution revenues in each class;
- Verification of the participation levels;
- Where savings information is not provided in the list of inputs and assumptions posted on the Board’s website. the distributor should comply with the guidelines set out in section 6.2.3 respecting custom projects;
- A statement as to whether the distributor has varied from the list of inputs and assumptions as posted on the Board’s website. Where the distributor has varied from that list of inputs and assumptions, the distributor should provide detailed evidence to support the alternative data, including, at a minimum, a completed “Input Assumptions Template”; and
- Duration of the program in years or months.

For programs funded in 2010 and beyond, the following information should be provided, in addition to the guidelines set out above:

- An Evaluation Report, in accordance with the guidelines set out in section 6.4; and
- All reports completed by an independent third party, in accordance with the guidelines set out in section 6.5.

All information filed in support of the LRAM claim should correspond to program information used in the calculation of the benefit-cost analysis.

10.1.3 Shared Savings Mechanism (SSM) and Other Financial Incentives

Section 5.0 contains information on the programs that are eligible for SSM and other financial incentives, the calculation of SSM and other incentives, and the timing of any application for recovery of SSM or other financial incentives.

An application for SSM or other financial incentives should include:

- Natural gas savings (both gross and net of free riders) for each program and for each class;
- The free rider rate applied to each program. Where different activities within a program have different free rider rates, the free rider rate for each activity should be provided;
- A calculation of the impact of the DSM program on distribution revenues in each class;

- Verification of the participation levels;
- Where savings information is not provided in the list of inputs and assumptions as posted on the Board's website, the distributor should comply with the guidelines set out in section 6.2.3 respecting custom projects;
- A statement as to whether the distributor has varied from the list of inputs and assumptions as posted on the Board's website. Where the distributor has varied from that list, the distributor should provide detailed evidence to support the alternative data, including, at a minimum, a completed "Input Assumptions Template;" and
- Duration of the program in years or months.

For programs funded in 2010 and beyond the following information should be provided in addition to the information set out above:

- An Evaluation Report, in accordance with the guidelines set out in section 6.4; and
- All reports completed by an independent third party, in accordance with the guidelines set out in section 6.5.

10.1.4 Adjustments to an Approved Plan

An application for adjustments to an approved ~~plan should include:~~multi-year DSM plan should occur only in exceptional circumstances. Any application for an amendment must meet a very high onus to demonstrate undue harm absent the application. Where such an application is made, it should include evidence to demonstrate the likelihood of undue harm in the absence of the application being made and any other supporting evidence.

- ~~Current and proposed budgets for programs affected by the re-allocation;~~
- ~~A description of the programs from which, and to which, funds are being re-allocated;~~
- ~~Whether the distributor is requesting that the Board to proceed in accordance with section 21 (4)(b) of the *Ontario Energy Board Act, 1998* under which the Board can dispose of the proceeding without a hearing; and~~
- ~~Where funding is being allocated to a program or programs that are not part of the distributor's approved DSM plan, the distributor should apply for approval of the proposed new program(s) at the time at which it applies for the proposed budget re-allocation.~~

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Appendix A

REVISED DRAFT DEMAND SIDE MANAGEMENT GUIDELINES FOR NATURAL GAS DISTRIBUTORS

EB-2008-0346

Date: February 20, 2009

TABLE OF CONTENTS

Page

1.0 OVERVIEW 5

1.1 Background 5

1.2 Overview of Draft Guidelines 5

2.0 COST EFFECTIVENESS 6

2.1 TRC Calculation 7

2.2 TRC Benefits 9

2.2.1 Avoided Costs 9

2.2.2 Natural Gas Savings 10

2.3 Inputs and Assumptions 11

2.4 TRC Costs 11

2.4.1 Equipment Costs 11

2.4.2 Program Costs 12

2.5 Adjustment Factors in the TRC Test for Assessing DSM Programs 14

2.5.1 Free Riders 14

2.5.2 Attribution 15

2.5.3 Spillover 16

2.5.4 Persistence 16

2.6 Fuel Switching 17

2.7 Pilot Programs 17

3.0 DSM BUDGETS AND TARGETS 17

3.1 Budget Determination 17

3.2 Budget Term and Reporting 18

3.3 Adjustments to an Approved Plan 18

3.4 Targeted Program Spending 19

3.5 TRC Savings Metrics 19

3.6 Market Transformation Metrics 19

3.7 Low-income Customer Program Metrics 20

4.0 LOST REVENUE ADJUSTMENT MECHANISM (LRAM) 20

4.1 Eligible Programs 21

4.2 Calculation of LRAM 21

TABLE OF CONTENTS
(continued)

Page

4.3 Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) 22
4.4 Timing of LRAM Application 22
5.0 INCENTIVE PAYMENT MECHANISMS 22
5.1 Eligible Programs 22
5.1.1 Shared Savings Mechanism (SSM) for Resource Acquisition Programs 23
5.1.2 Market Transformation Incentive 23
5.1.3 Low Income Customer Programs Incentive 24
5.2 Shared Savings Mechanism Variance Account (SSMVA) 24
5.3 Timing of Application 24
6.0 PROGRAM EVALUATION AND AUDIT 24
6.1 Evaluation Plan 26
6.2 Program Type Specific Guidelines 26
6.2.1 Direct Acquisition Programs 27
6.2.2 Market Support Programs 27
6.2.3 Custom Projects 28
6.2.4 Market Transformation Programs 29
6.2.5 Low Income Customer Programs 29
6.3 Implementation of Updated Input Assumptions 29
6.4 Evaluation Report 30
6.5 Independent Third Party Review 31
7.0 DSM CONSULTATIVE 32
8.0 ACCOUNTING TREATMENT 33
8.1 Funding of DSM Programs 33
8.2 Cost Allocation 34
8.3 Revenue Allocation 34
8.4 Demand Side Management Variance Account (DSMVA) 34
8.5 Carbon Dioxide Offset Credits Deferral Account (CDOCDA) 34
8.6 Recording of DSM Spending Not Funded Through Distribution Rates 35

TABLE OF CONTENTS
(continued)

Page

9.0 ANNUAL REPORTING GUIDELINES 35

10.0 ADMINISTRATION 37

10.1 Filing Guidelines (New) 37

10.1.1 Program Funding through Distribution Rates 37

10.1.2 Lost Revenue Adjustment Mechanism (LRAM) 39

10.1.3 Shared Savings Mechanism (SSM) and Other Financial Incentives 40

10.1.4 Adjustments to an Approved Plan 41

1.0 OVERVIEW

1.1 Background

The Ontario Energy Board (the Board) determined the original regulatory framework for gas distributor (“distributor” or “utility”) sponsored Demand Side Management (“DSM”) programs through guidelines established in its EBO 169-III Report of the Board dated July 23, 1993. DSM programs are programs which assist distributor customers in reducing their natural gas consumption. Union Gas Limited (“Union”) and Enbridge Gas Distribution Inc, (“EGD”) filed DSM plans in response to the directives of the Board in the EBO 169-III Report until 2006.

In 2006, the Board conducted a hearing on generic issues related to distributor DSM activities (EB-2006-0021).

The Board’s August 25, 2006 decision in the generic proceeding dealt with a large number of issues relating to DSM. A rules-based and framework approach was established where appropriate and practical, which the Board expected would result in significant regulatory savings for the parties, the Board and, ultimately, for ratepayers. Below is a list of the broader matters that were agreed by stakeholders and decided by the Board in that decision.

- A three-year term for the first DSM plan
- Processes for adjustments during the term of the plan
- Formulaic approaches for DSM targets, budgets, and distributor incentives
- Determination of how costs should be allocated to rate classes
- A framework for determining savings
- A framework and process for evaluation and audit
- The role of distributors in electric conservation and demand management activities and initiatives

In a separate decision dated October 18, 2006, the Board approved the input assumptions based on which Union and EDG filed their three-year DSM plans. DSM plans for each of Union and EDG were subsequently approved by the Board, and expire in 2009.

1.2 Overview of Draft Guidelines

On October 31, 2008, the Board initiated a consultation process on the development of Demand Side Management Guidelines for Natural Gas Distributors (the “Guidelines”) to assist in the development of next generation of gas distributor DSM plans. The Guidelines are expected to be applicable to natural gas distributor DSM initiatives beginning in 2010, and should be used in the preparation of distributor DSM plans. Those plans, including budgets, program targets and other related matters, will be considered by the Board in the context of rate proceedings for each of the distributors.

These draft Guidelines have been developed by Board staff following consultations with gas distributors and other interested stakeholders. The draft Guidelines largely consolidate existing Board policies in relation to DSM activities as reflected in the following DSM–related decisions and orders of the Board:

- EBO 169-III Report of the Board dated July 23, 1993; and
- The decisions for Phases I, II, and III of the DSM generic proceeding (EB-2006-0021).

By way of exception, the draft Guidelines propose changes in the following areas:

- Development of inputs and assumptions (section 2.3)
- Adjustment factors in the Total Resource Cost test for assessing DSM programs:

Spillover effects (section 2.5.2)

Persistence of savings (section 2.5.3)

- Development of DSM budgets and targets (section 3.0)

Low-income customer programs

- Incentive payment mechanisms (section 5.0)

Shared savings mechanism for resource acquisition programs

Market transformation incentive

Low income customer programs Incentive

- Program evaluation and audit (section 6.0)
- Annual reporting guidelines (section 9.0)
- Filing guidelines (section 10.0)

For symmetry, the draft Guidelines incorporate elements of the “Guidelines for Electricity Distributor Conservation and Demand Management” issued by the Board in 2008 (EB-2008-0037).

2.0 COST EFFECTIVENESS

The Total Resource Cost (TRC) test is the appropriate test to measure cost effectiveness. This test should be used by utilities when evaluating the cost effectiveness of a measure or program to determine the cost-effectiveness of a measure or program.[1]

The TRC test measures the benefits and costs of DSM efforts from a societal perspective. Under the TRC test, benefits are driven by avoided resource costs, which are the marginal costs that are avoided by not producing and delivering the next unit of natural gas to the customer. In addition, it includes the reduction in use of other resources such as electricity, water or other resources. Marginal costs (or avoided costs) include natural gas costs (both system and customer) and distribution costs (e.g., pipes, storage, etc.).

Costs in the TRC test are the costs of any equipment and program support costs associated with delivering that equipment to the marketplace.

Benefits	**Costs[2]**
Avoided natural gas supply costs	Equipment costs
Other avoided resource costs	Distributor program costs

This section sets out the expectations regarding the benefit-cost analysis for DSM programs.

2.1 TRC Calculation

Evaluating the cost effectiveness of DSM can be done in stages at many different levels, including technology or measure, program, and portfolio. The TRC test should be performed at each level, as appropriate. For some generic examples of how to apply the TRC Test see Appendix A of the Guidelines for Electricity Distributor Conservation and Demand Management (EB-2008-0037).

At the most detailed level, a TRC test can be performed to evaluate the cost effectiveness of a measure or technology. At the technology level, the TRC test takes into account the benefits, which are the avoided natural gas supply costs and other avoided resource costs, and the equipment costs. There are no other adjustments to the TRC test at this stage of the evaluation.

The results of the TRC test should be expressed as a net present value (NPV). As a NPV assessment, the TRC test sums the streams of benefits and costs over the lifetime of the equipment/technology and uses a discount rate to express these streams as a single "current year" value. Thus, the NPV_{TRC} is the net discounted value of the benefits and costs over a specified period of time (usually dictated by the equipment life of the DSM technology).

[1] National Action Plan for Energy Efficiency (2008). Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers. Energy and Environmental Economics, Inc. and Regulatory Assistance Project.

[2] In the case of fuel switching measures, the costs of the other fuels should be included.

The TRC test is a measure of the change in the total resource costs to society, excluding externalities, of the DSM program. If the NPV_{TRC} is positive, or the benefit to cost ratio exceeds 1, indicating that benefits exceed costs and is cost effective from a societal perspective.

Since the resource acquisition portion of the utility shared savings mechanism is based on sharing a portion of the customer net savings (TRC) that the utility programs generate, it is anticipated that utilities will be incented to increase TRC where possible at a portfolio level. However, in some cases to facilitate customer needs it may be necessary to undertake certain projects that are individually below a TRC ratio of 1.

Once the program costs have been assessed, the TRC test can be performed again to evaluate the cost effectiveness of the program. At the program level, the TRC test takes into account the following:

- The costs and benefits as estimated at the technology level;
- The distributor program costs, excluding verification, measurement and evaluation costs; and
- Further adjustments to account for free ridership, spillover, persistence of savings, etc.

Finally, several programs are bundled together, further indirect costs are included and the TRC test is carried out once again to evaluate the cost effectiveness of the portfolio. This three layered structure; technology or measure, program and portfolio, is key to performing TRC analyses.

The NPV_{TRC} formula is as follows:

The NPV_{TRC} formula is as follows:

$$NPV_{TRC} = B_{TRC} - C_{TRC}$$

where;

$$B_{TRC} = \sum_{t=1}^{N} \frac{AC_t}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^{N} \frac{UC_t + PC_t}{(1+d)^{t-1}}$$

and,

B_{trc}	=	the benefits of the program
C_{trc}	=	the costs of the program. Where a measure includes fuel switching for a given end use, the cost of the other fuel must be included in the cost component of the TRC formula.

AC_t	=	avoided costs in year t
UC_t	=	distributor program costs in year t
PC_t	=	participant cost in year t
N	=	number of years for the analysis (i.e., the equipment life of the DSM technology)
d	=	discount rate.

Note: Distributors should use a discount rate equal to the incremental after-tax cost of capital, based on the latest prospective capital mix, debt and preference share cost rates, and approved rate of return on common equity.

2.2 TRC Benefits

2.2.1 Avoided Costs

As noted above, the TRC test assesses DSM costs and benefits from a societal perspective. The benefits are defined as "avoided costs." This represents the benefit to society of not having to provide an extra unit of supply of natural gas to the customer. For natural gas distributors, supply costs include the gas commodity and the avoided distribution system costs (e.g., pipes, storage, etc.).

Certain DSM programs may have other benefits, including savings of other energy sources such as electricity, heating fuel oil, propane or water. While these savings are not generally the primary target of the program, the TRC test will accommodate an assessment of savings associated with avoiding the use of these resources. In these cases, the benefits accrue from the avoided costs associated with these resources. Utilities wishing to assess resource savings relating to other energy forms or water will need to use avoided cost estimates for those resources in the same manner that natural gas avoided costs are used.

The TRC test involves an analysis over the life-cycle of the DSM measure. To accommodate this, long-term projections of avoided costs should also be undertaken. Also, any DSM measures included in the analysis should have equipment life estimates along with estimates of savings and costs.

Each distributor should calculate avoided costs for natural gas, other energy forms and water that reflect the cost structure and franchise area of the distributor. In order to ensure consistency, a common methodology should be used to determine the costs. The distributors should coordinate the timing for selecting commodity costs so that they are comparable.

The avoided costs should be submitted for review as part of the DSM plan filing and should be in place for the duration of the plan. The commodity portion of the avoided costs should be updated annually.

As avoided costs are long term projections, updating the costs, other than the commodity costs, on a multi-year cycle should not cause benefits to be significantly under or overstated. Regardless of how often the avoided costs are updated, the same avoided costs are expected to be used to calculate both the target and incentive amount. It is therefore anticipated that the relative impact of avoided costs on TRC would be minimal.

Estimating the natural gas avoided costs should include the following analytical steps:

1. estimate marginal natural gas commodity costs;

2. estimate marginal distribution costs;

3. determine the appropriate costing periods, if applicable; and

4. attribute marginal costs to the costing periods, if applicable.

Marginal cost studies typically involve detailed analyses starting with an understanding of the current costs for gas commodity and distribution (e.g., pipes, storage, etc.).

2.2.2 Natural Gas Savings

The benefits in the TRC test are driven mainly by the annual energy savings (e.g. natural gas). They are often calculated at the technology level and are commonly referred to as "prescriptive" savings estimates. For programs that rely on prescriptive savings estimates, savings are calculated by multiplying the per unit (i.e., single technology) savings with the number of units installed.

Savings and technology costs should be defined relative to a frame of reference or "base case." To accurately specify the impacts of any given technology, the analyst should know what would have happened in the absence of the technology. The base case technology variable represents the piece of equipment or technology that is being replaced by a more efficient technology. The application of a base case technology can vary; for example, in the case of a DSM program consisting of a residential programmable thermostat, the base technology would be a manual thermostat. In the example of a program consisting of a high efficiency furnace, the base case equipment would be the homeowner's current furnace. At a minimum, the base case technology should be equal to or more efficient than the technology benchmarks mandated in energy efficiency standards.

In practice, specifying savings relative to a frame of reference can be simply characterized by the three general decision types:

- new;
- replacement; or
- retrofit.

In the TRC analysis, equipment life is used to determine the time period over which the net present value analysis is carried out. The equipment life variable represents the number of years that the more efficient equipment installed is assumed to produce natural gas savings. The benefits (i.e., natural gas savings) from an energy efficient piece of equipment are assumed to persist for the life of the equipment. Equipment life is estimated based on the nature of the equipment and an assumed usage pattern.

An important consideration when assessing equipment life is the potential difference between the energy efficient equipment and the "base case" equipment that is being replaced. A simplifying assumption in the case of replacement programs is that the energy efficient equipment lives are the same as in the base case. However, there are some technologies where the energy efficient equipment has a much longer life than the base case equipment, which should be accurately accounted for, when practical.

2.3 Inputs and Assumptions

The inputs and assumptions for a selection of measures, covering a range of typical DSM activities/technologies in residential, commercial and industrial applications are being developed by the Board with assistance of an external consultant and with input from distributors and other stakeholders. The approved inputs and assumptions will be posted on the Board's website. Distributors should use this data for undertaking benefit-cost analyses of DSM measures and programs.

Distributors may use other data where appropriate and justified. However, where a distributor uses other data the distributor should provide detailed evidence to justify its use.

2.4 TRC Costs

The TRC includes two types of DSM costs:

1. equipment costs; and
2. program costs.

2.4.1 Equipment Costs

Typically in DSM programs, equipment costs are paid by the participant/customer. Customer equipment costs (sometimes termed "participant costs") are the costs to purchase the more efficient equipment. They include capital, installation and operating and maintenance (O&M) costs associated with the technologies of the DSM program. It is important to note that the TRC test does not differentiate between who (distributor or customer) pays the cost of the equipment.

Customer costs can be incremental or full depending upon the nature of the energy efficiency investment decision. Incremental equipment costs are defined as the cost of the energy efficient technology above the base case technology. In the same way that the base case is important for specifying the savings, it is also important for specifying the cost of the energy efficient equipment. For example, in a replacement scenario, the cost of the energy efficient technology is typically incremental. In a retrofit or discretionary investment case, the cost of the energy efficient technology would be the full cost of the equipment.

Equipment costs, whether paid by the customer or the distributor, including purchase and installation, should always be defined relative to a base case. It is not enough to know the installed cost associated with the energy efficient equipment used in the program. To calculate the impact of the program, the cost of the equipment that would have been purchased in the absence of the program, the base case, should also be known. The appropriate specification of incremental cost for use in the TRC analysis is the difference between the base case and the energy efficient purchase.

As in the case of savings, there are typically three generic categories for specifying equipment costs, representing the type of investment decision:

- new;
- replacement; or
- retrofit.

The information sources for equipment costs will vary. For residential equipment, retail store prices are appropriate sources of information for many technologies including appliances and "do-it-yourself" water heater or thermal envelope upgrades. It is common practice to specify an average price based on a sample of retail prices. For commercial and industrial equipment, cost data can be more complicated to acquire due to limited access and confidentiality concerns. For larger "custom" projects, invoices or purchase orders, when available, may be one method to support the cost estimate.

Equipment that requires O&M expenditures is often not incremental (i.e., those costs would have been incurred in the base case anyway). However, if the energy efficient equipment requires significantly more/less maintenance than its less energy efficient counterpart, the incremental/decreased O&M costs need to be factored into the TRC analysis. There will be exceptions and a proper TRC analysis should incorporate these.

2.4.2 Program Costs

From the perspective of the TRC test, DSM program costs are those incurred by the distributor. These costs include the marketing and support costs associated with delivering the DSM activity. Participant or customer incentive costs, which are considered transfers in the TRC test, are not included in the analysis.

Distributor costs typically cover a number of activities such as marketing and advertising, consulting, channel support, monitoring and evaluation. There are five major categories of distributor costs:

(i) development and start-up;
(ii) promotion;
(iii) equipment and installation;
(iv) monitoring and evaluation; and
(v) administration.

In practice, all of these costs can be expected for programs that utilities in Ontario might be considering. For an accurate TRC assessment, the distributor should ensure that all costs associated with designing, operating and tracking the programs, other than incentive costs, are accounted for in its TRC analysis.

i. Development and Start-up Costs

Development and start-up costs are different from on-going operating costs. For example, initial costs may be incurred to train distributor staff in the use of the equipment or techniques used in a program and usually occur at the early stages of the program's life. Costs of developing DSM plans and procedures are also often concentrated in the early program years. In general, start-up costs are only a small component of the total costs in the life cycle of a DSM program.

ii. Promotion Costs

Promotion costs may be incurred to educate the customer about a DSM program and will vary by program type and level of promotional effort. The cost of promotion depends on the method employed, the market segment and the DSM measures promoted. Program promotion may also involve trade-offs between increases in promotion costs and expected increases in participation.

As noted above, incentive payments from the distributor to a customer for participation in a program are <u>not</u> a component of the TRC analysis, but still should be included in the distributor's program budget. The incentive merely represents a transfer payment between two parties involved in the program.

iii. Distributor Equipment and Installation Costs

Distributor equipment and installation costs include the costs of any distributor devices needed to operate the programs such as specialized software or tools, as well as any equipment directly installed by the distributor.

iv. Monitoring and Evaluation Costs

This section focuses on the cost to the distributor of monitoring and evaluating a DSM portfolio.

There are two broad categories of evaluation activity: impact evaluation and process evaluation. Impact evaluation focuses on the specific impacts of the program – for example, savings and costs. Process evaluation focuses on the effectiveness of the program design – for example, the delivery channel. The costs associated with each of these activities are program costs that need to be included in the TRC analysis at the portfolio level.

Monitoring and evaluation costs are incurred for systems, equipment and studies necessary to track measurable levels of program success (participants, impacts on consumption and costs) as well as to evaluate the features driving program success or failure. It is important to develop the necessary tracking systems at the time of program design. At a minimum, the tracking system should collect information on the key components that drive the TRC test, including:

- number of participants/installations;
- natural gas savings;
- cost of equipment; and
- distributor program costs.

To facilitate the evaluation of DSM programs and results, utilities should have clearly documented "paper trails."

v. Administrative Costs

Administrative costs are generally the costs of staff who work on DSM activities. These costs are often differentiated between support and operations staff. Support staff costs are considered fixed costs or "overhead" that occur regardless of the level of customer participation in the programs. Operations staff costs are variable, depending on the level of customer participation. Utilities should include all staff salaries that are attributable to DSM programs as part of the costs in the TRC analysis.

2.5 Adjustment Factors in the TRC Test for Assessing DSM Programs

In performing a TRC analysis of a DSM program, several adjustments should be made to the benefits side of the equation. These adjustments include:

- free ridership of participants (section 2.5.1);
- attribution of the benefits (section 2.5.2);
- spillover effects (section 2.5.3); and
- persistence of the measures (section 2.5.4).

2.5.1 Free Riders

Free rider adjustments are a component of the TRC test when it is applied in the assessment of a program. The standard definition of a free rider is "a program participant who would have installed a measure on his or her own initiative even without the program."[3] This participant simply uses the program to offset the cost of installing or undertaking the energy efficient initiative.

Costs and benefits associated with free ridership should be assessed as part of the TRC analysis of a program. In determining overall savings of a program, these participants are excluded from the benefits attributed to the program. The equipment costs associated with these participants is similarly excluded from the cost side of the equation.[4] However, all program costs associated with free riders should be included in the analysis.

Assumptions on free ridership should be assessed for reasonableness prior to implementation of the plan or program and should be reviewed and updated over the course of the multi-year plan as part of each distributor's ongoing evaluation and audit processes.

2.5.2 Attribution

The concept of attribution has been assessed by the Board in previous proceeding and most recently in EB-2006-0021 where the Board decided:

> "… the Board accepts the centrality principle for purposes of the first multi-year DSM plans, under which the utility would be entitled to 100% of the TRC benefits if it can be demonstrated that it has a central role in a program. That is, as the utilities proposed, if the utility initiated the partnership, initiated the program, funded the program, or implemented the program." (EB-2006-0021 Board Decision with Reasons, August 25, 2006. page 42)

Prohibitive and excessive rules related to attribution have the potential to restrict partnerships that can enhance conservation for Ontario. In the Board's Decision With Reasons in RP-2003-0203, paragraph 6.7.14, page 61, the Board indicated:

> "The Board is not concerned about the Company partnering with others to accomplish TRC savings, based upon the goal of achieving the greatest possible DSM benefits at the lowest cost, and in the simplest way possible."

Attribution of benefits as between a distributor and a non-rate regulated third party will be determined on a case-by-case basis.[5] In order for the distributor to claim 100% attribution of benefits, the distributor should demonstrate that its role was 'central' to the program.

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

[4] Eto, J, (1998) Guidelines for assessing the value and Cost-effectiveness of Regional Market Transformation Initiatives. Northeast Energy Efficiency Partnership, Inc.

[5] See the March 3, 2006 Decision of the Board in proceeding RP-2005-0020/EB-2005-0532.

TRC benefits for program partnerships with Board rate-regulated entities such as electricity distributors should be allocated in the manner indicated in the Board's "Guidelines for Electricity Distributor Conservation and Demand Management". Where specific agreements have been developed by parties to deal with attribution for a program, these more case specific rules should be applied, so long as there is no double counting.

2.5.3 Spillover

Spillover addresses customers that adopt efficiency measures because they are influenced by [a distributor's] program-related information and marketing efforts, though they do not actually participate in the program".[6] Due to these spillover customers in the distributor's franchise area, the distributor will lose revenue due to a lower demand for natural gas and the TRC savings could be underestimated. This in turn could affect the SSM claim.

Spillover is to be applied in a manner consistent with other TRC test adjustments. A distributor that wishes to include spillover should assess these impacts on the same basis as other input assumptions to the TRC Test (e.g. free ridership)..

Spillover is defined as:

> Spillover is comprised of energy savings that are due to the program but not counted in program records. Spillover is a combination of several factors that may influence non-reported actions to be taken at the project site itself (inside spillover), at other sites by the participating customer or Energy Efficiency Contractors (outside spillover), or by non-participants (non-participant spillover). For example, a participating customer or Energy Efficiency Contractor might observe the benefits of installing efficiency measures at a program site and, based on this experience, install the same or similar measures at other sites without formally participating in the program. Spillover savings are added to the program's installed gross savings.

2.5.4 Persistence

Persistence is a measure of how long a DSM measure is kept in place by the customer. Persistence can have an effect on overall net program savings estimates, but can also be costly to measure. For example, if an energy efficient measure with a 15-year lifetime is removed after only two years, most of the savings expected to result from that installation will not materialize. For most common technologies such as furnaces and

[6] U.S. Department of Energy (2008). Understanding Cost Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy Makers.

boilers, it is reasonable to assume that the equipment will not be removed from the building due to operational requirements.

Distributors will be expected to consider persistence of savings in their next generation DSM plans and evaluations of programs. The potential accuracy gained by measuring persistence should be balanced against the costs involved.

2.6 Fuel Switching

Where fuel switching away from natural gas aligns with the distributor's DSM objectives, the distributor may pursue these activities.

Fuel switching to natural gas is not a DSM activity and DSM funds should not be used for this purpose.

2.7 Pilot Programs

A pilot program is one that involves the installation, testing or evaluation of technologies that are not already in use in Ontario, or in limited use, and that serves as a tentative model for future development. They can also test new delivery channel or marketing approaches to overcome barriers to market entry. Pilot program may be helpful for application to resource acquisition, market transformation or low income programs.

A properly structured pilot should provide an opportunity to gain experience in business processes, installation procedures, logistics, deployment, integration issues, customer communications, and customer impacts. A distributor should provide a rationale for how its program will increase the collective understanding of the technology and its benefits as a DSM measure. Pilot programs that have a TRC ratio of less than 1.0 are detrimental to the utility resource acquisition SSM. Therefore, a utility will only pursue these initiatives where it is expected to generate positive TRC in future years. Utilities should be prepared to share the results and knowledge gained through the pilot with the Board and other utilities.

3.0 DSM BUDGETS AND TARGETS

3.1 Budget Determination

In recognition of the knowledge and experience that the natural gas utilities have gained in developing and implementing DSM plans, distributors should propose a budget for their respective DSM plans. However, each distributor will need to justify its proposed DSM budgets based on:

- the results anticipated from its proposed multi-year DSM plans, and,
- the government's policies/initiatives in advancing conservation in Ontario.

Distributors should propose separate DSM budgets in the following program areas:

- Resource acquisition (TRC Net Savings)
- Market transformation
- Low income customers

Distributors are encouraged to consult with relevant stakeholders in developing their budgets for their DSM programs.

3.2 Budget Term and Reporting

There are benefits associated with multi-year funding for ongoing programs. Multi-year funding supports better planning and management and facilitates the utilities' entering into of partnerships with other delivery agents.

Distributors may therefore apply to the Board for multi-year DSM funding for up to 5 years. The term of the DSM budget will be the subject of a Board proceeding where distributors and stakeholders will have the opportunity to provide their views to the Board.

When applying to the Board for funding, budgets, LRAM and SSM or other financial incentives they should be developed and measured on an annual basis (market transformation amounts may be an exception). Annual budget amounts will be an input to each year's distribution rate adjustment.

The application submitted to the Board should be in the form of a DSM plan, which includes a budget and an evaluation plan. The budget should include cost estimates for administration, evaluation, research (including market potential studies) and support.

A DSM variance account should be used to "true-up" any variances between the spending estimate built into rates for the year and the actual spending in that year. If the Board has approved budgets with terms longer than one year, unspent funds can be carried over to a subsequent year. At the end of the approved funding term, any unspent funds will be returned to ratepayers through rates.

Where programs have been more successful than expected, such that the annual budget is insufficient, the distributor may spend up to an additional 20% above the annual DSM budget as long as these funds are used for incremental program purposes. Such additional funding is usually required late in the program year and an immediate response is needed to avoid damaging successful momentum. Spending of these funds is to be recorded for clearance in the DSM variance account.

3.3 Adjustments to an Approved Plan

Utilities should evaluate the effectiveness of programs on an ongoing basis, and make adjustments as necessary to improve program design, performance, and uptake by customers. Program factors such as the economy or other environmental factors can fluctuate within any given year. Flexibility during a program year has been a key factor for success for the natural gas utilities. If the multi-year DSM plan approved by the

Board requires adjustments during the term, the utility should make an application for amendment to the Board. Experience from the previous Board approved multi-year plan has demonstrated that this scenario is very unlikely..

3.4 Targeted Program Spending

There is a tension between ensuring that each rate class is allocated an appropriate portion of DSM funds, on the one hand, and the benefits of targeting spending to the most cost effective programs regardless of what rate class they apply to, on the other. As a principle, DSM programs should provide customers in all rate classes and sectors with equitable access to DSM programs to the extent reasonable. This principle must be balanced against and consistent with the principle of optimizing cost-effective DSM opportunities.

If DSM sector (i.e., residential, commercial, or industrial) level spending is significantly different than the historical percentage levels of spending in those sectors, the distributor should provide its explanation for this in its proposed DSM plan. The Board will then determine whether to approve the revised spending ratios and, if so, under what conditions.

To the extent that actual sector level spending then varies significantly from the ratios identified in the plan, interested parties may challenge the appropriateness of the deviation from the plan when the distributor seeks approval for the clearance of the relevant accounts.

Market potential studies, or updates to an existing study, should be filed by each distributor together with its DSM plan. The distributor may, at its discretion, do additional studies of market potential or updates during its plan. The results of these studies could inform distributors in allocating DSM budgets among different sectors, rate classes, types of markets etc.

3.5 TRC Savings Metrics

Resource acquisition programs produce measurable results. The Total Resource Cost (TRC) test assesses the net benefits of DSM activities from a societal perspective. A shared savings mechanism provides for a sharing of DSM benefits between customers and the utility. It is expected that a fair and consistent sharing of benefits between ratepayers and the utility will incent the utility to optimize TRC benefits in the resource acquisition portfolio. TRC savings targets are not required in respect of resource acquisition programs.

3.6 Market Transformation Metrics

Market transformation programs are those that are designed to make a permanent change in the marketplace over a long period of time. In order to support Ontario's aggressive goals to grow the amount and diversity of renewable energy source, renewable energy initiatives that typically do not measure specific TRC may be included within Market Transformation.

Such programs are not amenable to a formulaic evaluation approach and therefore should be assessed on an individual basis using metrics which are suitable to a given program. Such metrics should be objective and able to measure success objectively, such as activities undertaken, or changes in market share of a DSM technology. Depending on the program, other quantifiable metrics could include increase in consumer awareness due to an educational program and the like. Distributors are expected to propose specific metrics for any proposed market transformation program.

For each market transformation program the utility should propose a program description, goals (including measurement method), shareholder financial incentives (including structure and payment), length, level of funding and program elements.

3.7 Low-income Customer Program Metrics

Low-income customers face certain barriers in accessing DSM programs which are unique to this group of customers. In addition, the TRC net savings for these programs are typically low relative to the savings of other programs although very valuable for this market sector.

Targets for these programs could be based in part on TRC savings for these programs but also in part on other metrics such as market penetration of DSM programs in the low income segment of the population.

Distributors are expected to develop eligibility criteria and program parameters for low income residential programs. Criteria presently used by various levels of government for the purposes of determining eligibility for low-income consumer programs may be appropriate for use by distributors.

Distributors are also expected to propose explicit metrics for the DSM programs targeted at low income consumers.

4.0 LOST REVENUE ADJUSTMENT MECHANISM (LRAM)

Unforecasted DSM results can have the effect of eroding distributor revenues due to lower than forecast throughput. Utilities recover fixed distribution costs through both a fixed and a variable rate, which is set based on a forecast of consumption, including natural changes in energy efficiency. If actual consumption is less than the forecasted amount used for rate-setting purposes, the distributor earns less revenue than it otherwise would have, all other things being equal. Since the intention and effect of DSM activities is to reduce natural gas use, it also has the effect of reducing throughput and associated distributor revenues, which can result in a disincentive for utilities to deliver DSM programs.

A mechanism to compensate for distributor-induced lost revenues is intended to remove the disincentive. LRAM is a retrospective adjustment, which is designed to recover revenues lost from distributor supported DSM activities in the prior year. It is designed to compensate a distributor only for unforecasted lost revenues associated with DSM activities undertaken by the distributor within its franchise area.

4.1 Eligible Programs

The LRAM applies to programs implemented by the distributor, within its franchise area, including programs delivered by the distributor itself and/or programs delivered for the distributor by a third party (under contract with the distributor).

Distributors may undertake some programs in partnership with other entities, such as electricity distributors or community agencies. In assessing the distributor's involvement in program delivery, and the resulting potential impacts on revenue, distributors should be guided by section 2.5.2 regarding the attribution of benefits.

4.2 Calculation of LRAM

The LRAM is determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class. Lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time. The first year impact will be calculated as 50% of the annual fully effective volumetric impact multiplied by the distribution rate for each of the rate classes that the volumetric variance occurred in.

As indicated by the filing guidelines set out in section 10.1, utilities should include in the application for recovery of LRAM the volumetric impact of measures and programs implemented in a specific year. Volumetric savings, costs of programs, free riders and other adjustments, as discussed above, should be based on the results of the evaluation and audit work completed for the year for which LRAM is applied. The impacts should be calculated for each program and for each class both gross and net of free riders. The amount to be recovered through rates will be determined as net of free riders and spillover effects.

By way of example, if in June of 2008 the audit of the 2007 programs is completed and demonstrates a change in assumptions, that change will apply for LRAM purposes from the beginning of 2007 onwards until changed again. Best available information for the purposes of LRAM is that information available to the distributor immediately prior to the commencement of the audit by the independent third party.

Utilities will be expected to file an audit report and any back up program evaluation reports needed to support the volumes used in the LRAM calculation. The audit report should be prepared by an independent auditor and provide an opinion on the LRAM proposed and any necessary amendment thereto.

4.3 Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)

The purpose of the LRAMVA is to record the amount of distribution margin gained or lost when the distributor's DSM programs are less or more successful than budgeted. When the distributor's DSM programs are less successful in the test year than budgeted, the distributor gains distribution margin. Similarly, the distributor loses distribution margin in the test year when its DSM programs are more successful than budgeted.

4.4 Timing of LRAM Application

An application to clear the balance in the LRAM variance account, together with carrying charges, should be made on an annual basis.

5.0 INCENTIVE PAYMENT MECHANISMS

LRAMs remove a disincentive for utilities to implement DSM, but do not provide an incentive for utilities to successfully implement DSM programs. Given a certain level of resources, the distributor should make a trade-off between pursuing a DSM activity versus other activities.

Shareholder incentives are an appropriate way to encourage utilities to successfully pursue DSM programs.

5.1 Eligible Programs

The SSM and other financial incentives are available for customer focused initiatives that are funded through distribution rates and where the costs of the initiatives are expensed, such as efficiency improvements in the use of natural gas. The SSM and other financial incentives are not available for distributor-side expenditures or programs that are not funded through distribution rates.

Utilities may undertake some programs in partnership with other entities, such as electricity distributors or community agencies. In assessing the distributor's involvement in program delivery, utilities should be guided by the guidelines set out in section 2.5.2, regarding the attribution of benefits. A distributor may only claim a shareholder incentive in relation to its contribution to the program, as determined by the attribution guidelines.

Distributors can apply for separate incentives for the following types of programs:

- SSM for Resource Acquisition Programs (TRC Net Savings)
- Market Transformation Programs
- Low Income Programs

The SSM and other financial incentives are pre-tax amounts. In addition, the SSM should be calculated across the entire portfolio of DSM programs (excluding market transformation and low-income programs), including any programs with negative benefits.

The amount of any SSM and other financial incentives should not be included in the distributor's return on equity for the purposes of setting rates or in the calculation of any earnings sharing amounts.

5.1.1 Shared Savings Mechanism (SSM) for Resource Acquisition Programs

For SSM purposes, distributors should calculate the TRC net benefits of the DSM programs, and adjusting for free riders and spillover effects as required. The TRC savings from low income programs and market transformation programs should be excluded from this calculation since there is a separate incentive mechanism for low income customer programs as discussed in section 5.1.3 below.

To provide a consistent, fair and effective reward structure, the linear function relative to TRC savings as approved by the Board should be used. . This provides a transparent and straightforward incentive that will enable the distributor to balance DSM with other business objectives.

Regarding allocation of SSM costs among customer classes, DSM shareholder incentive amounts should be allocated to the rate classes in proportion to the net TRC benefits attributable to the respective rate classes.

The rules for calculation of TRC results for SSM purposes have been an important factor for driving utility activities over the past decade. These rules have been continuously approved by the Board over time, including in the most recent DSM Generic Hearing (EB-2006-0021). Assumptions used from the beginning of any year will be those assumptions in existence in the immediately prior year, adjusted for any changes in the audit of that prior year. By way of example, if in June of 2008 the audit of the 2007 programs demonstrates a change in assumptions, that change shall apply for SSM purposes from the beginning of 2008 onwards until changed again.".

The Board has spent considerable resources having Navigant Consulting Inc. update the measures assumption list. The Board approved measures list will provide distributors the certainty they need to make the necessary business decisions to pursue successful DSM.

5.1.2 Market Transformation Incentive

For market transformation programs, a utility could be entitled to an incentive payment based on the measured success of the programs relative to the established metrics discussed in section 3.6 above. This amount will be in addition to any amount earned as SSM discussed in section 5.1.1 above.

Incentive payments for market transformation programs should be made on an individual program basis. The incentive payment will be tied to the ability of the program to deliver (or surpass) the defined metrics.

The measurement and calculation methodologies to be used to determine whether the incentive has been earned in a year should be detailed by each distributor in its DSM plan.

5.1.3 Low Income Customer Programs Incentive

Incentive payments for low-income customer programs may be made on an individual program basis. This incentive will be in addition to any amount earned as SSM discussed in section 5.1.1 above.

Distributors are expected to use the program's approved evaluation metrics to determine the program's success relative to the established metrics discussed in section 3.7 above. The incentive payment will be tied to the ability of the program to meet (or surpass) its established targets.

The measurement and calculation methodologies to be used to determine whether the incentive has been earned in a year should be detailed by each distributor in its DSM plan.

5.2 Shared Savings Mechanism Variance Account (SSMVA)

The purpose of the SSMVA is to record the amount of the shareholder incentive earned by the distributor as a result of its DSM programs. The SSMVA account should include incentives earned from distributors from Resource Acquisition Programs (TRC Net Savings), Market Transformation Programs and Low Income Customer Programs.

The balance of this account, together with carrying charges, will be disposed annually.

5.3 Timing of Application

Distributors should apply for SSM and other financial incentives annually. Section 2.1.12 of the Natural Gas Reporting & Record Keeping Requirements (RRR) Rule for Gas Utilities includes the timing requirements for annual audited DSM results.

6.0 PROGRAM EVALUATION AND AUDIT

Effective monitoring, evaluation, verification and reporting of DSM program outcomes is a critical part of ensuring that programs are cost effective, generating the desired outcomes, and providing real savings to consumers. Evaluation also provides utilities with the future opportunity to identify ways in which a program can be changed or refined for greater efficiency in delivery and cost effectiveness.

Utilities should undertake evaluations of programs funded through distribution rates. The evaluation of DSM activities is important to support the Board's review and approval of LRAM, SSM and other financial incentive claims made by utilities.

Evaluation of the energy savings of a program is needed to determine the impact on a distributor's revenues as a result of reduced throughput.

The California Evaluation Framework identifies two key functions of evaluation:

1) To document and measure the effects of a program – "Summative Evaluations."

2) To help understand why those effects occurred and identify ways to improve the program – "Formative Evaluations."

The first function represents a threshold for assuring accountability for the expenditure of resources on that program. Evaluation activities are done after the program has been operating and focus on documenting impacts with a view to informing decisions regarding continuation, expansion or cancellation of the program. Formative evaluations (often referred to as process evaluations) may be done earlier in a program's continuum and focus on providing feedback regarding the operational effectiveness of a program. The results of the evaluation serve to inform decisions regarding mechanisms to improve the program.

A key tenet of good program evaluation practices is the identification of the evaluation activities as part of the initial program design. This ensures that the operational characteristics of the program generate the data and information that can assist in the program evaluation. This can be as simple as collecting relevant contact information as part of the operation of the program which will be used in follow-up activities, or more complicated activities such as pre and post implementation metering of equipment. In both cases, the evaluation techniques and parameters are integrated with the design and operation of the program.

It is incumbent on utilities to attempt to improve their programming capabilities over time. This may involve re-visiting the programs from time to time through the use of process evaluations that examine the effectiveness of the delivery. All programs should consider a certain level of process evaluation effort at some point. Typically, process evaluations occur earlier in a program's life rather than later – i.e., early enough to revise the program as a result of the evaluation. This will vary based upon the size and nature of the programs, where they are in their life, and the similarity (or lack of similarity) to other distributor programs. For small programs, the evaluation effort could focus on secondary research augmented by interviews with key personnel involved in the program. Larger programs might involve greater depth of evaluation including market research, surveys with participants and non-participants and related primary research activities. In the end, the intent is to ensure that programs operate at the highest level of effectiveness and that the process evaluation results are made available to other utilities to assist them in their delivery.

6.1 Evaluation Plan

An overarching element of effective evaluation is the need to identify, at the outset, how each program will be evaluated. The purpose of the Evaluation Plan will be to identify the key evaluation metrics, activities and outcomes associated with each of the distributor's DSM programs.

It is recognized that not all programs will need an evaluation effort in each year.

However, at a minimum the distributor should anticipate and plan for a certain level of evaluation activities over the continuum of a program's life.

In addition to meeting the evaluation objectives listed below, any Evaluation Plan should include the distributor's proposed methodology for:

- Assessing program effects (summative evaluation); and,
- Assessing why effects occurred, and how the program can be improved (formative or process evaluation).

The Evaluation Plan(s) should outline how the distributor will accomplish the following evaluation objectives:

- Assessing the level of natural gas savings achieved;
- Assessing cost-effectiveness;
- Informing decisions regarding LRAM, SSM and other financial incentive amounts;
- Providing ongoing feedback, and corrective and constructive guidance regarding the implementation of programs; and
- Helping to assess whether there is a continuing need for the program.

6.2 Program Type Specific Guidelines

This section focuses on the guidelines, in addition to those set out above, for tracking and measuring the effects of the following five types of DSM programs:

Direct acquisition programs are programs that have clear causality between distributor activity and natural gas and other resource savings.

Market support/outreach programs are programs in which the distributor supports outreach or educational efforts which generally promote the energy efficiency message, but where savings are indirect and it is difficult to see a clear cause and effect relationship.

Custom projects are those projects that involve customized design and engineering, and where a distributor facilitates the implementation of specialized equipment and technology that is not identified in the list of inputs and assumptions posted on the Board's website.

Market transformation programs are those that (a) seek to make a permanent change in the market for a particular measure, (b) are not necessarily measured by number of participants and (c) have a long term horizon.

Low income customer programs are those that are specially designed to reduce the natural gas consumption of low income customers.

6.2.1 Direct Acquisition Programs

Direct acquisition programs are relatively straightforward to track and measure. Tracking represents one of the administrative functions of program delivery. While the specifics will vary for each type of program, there is a need to show clear cause and effect between the distributor's activities and the customer's reduction of natural gas consumption. In direct acquisition programs, this is often precipitated by the processing of a participant incentive. Utilities will need to have systems for collecting relevant information for each program, including:

- technology type;
- number of installations;
- savings estimates;
- equipment cost estimates;
- customer address or location;
- delivery channel; and
- participant incentive amount.

It may not be feasible to collect all information for all programs. For example, a program delivered by a retailer that relies on in-store coupons will likely not have the means to track who actually used the coupons and received the product(s). However, the retailer can be expected to track information about the number of coupons turned in, and the distributor's tracking system could then calculate the resulting cost to the distributor. With this information, the distributor can then calculate the savings and equipment cost and combine the information with equipment life, free rider and spillover estimates and program costs - resulting in both a tracking report and the components of the TRC analysis.

In the case of a program delivered by a third party, tracking should include reports that the delivery partner provides to the distributor. These reports should provide details such as number of customers visited including address and equipment installed.

6.2.2 Market Support Programs

Natural gas savings from DSM activities related to training, public outreach and the general provision of information on efficient energy use are difficult to track, measure and establish clear causality. Since market support programs typically do not result in natural gas savings, other assessment criteria should be used to assess their benefits. A distributor should endeavour to have at least one metric for each market support activity.

Below is a sample of potential tracking activities that might accompany the delivery of market support program.

Support	Metric	Additional Information
Web-site calculator	Number of hits	Survey re: usefulness of website
Training sessions for contractors	Number of sessions Number of attendees	Survey re: specific activities undertaken by attendees
Home shows	Number of giveaways	Survey re: energy efficient appliances
Design workshops	Number of professional attendees	Surveys re: design activities

6.2.3 Custom Projects

Custom projects are those projects that involve customized design and engineering, and where a distributor facilitates the implementation of specialized equipment or technology not identified in the list of inputs and assumptions as posted on the Board’s website. Projects that involve a combination of several measures provided in that list of inputs and assumptions are not considered to be custom projects.

For a custom project, utilities will need to track:

- the type of equipment that was installed;
- the related savings and equipment cost; and
- distributor support costs.

Since custom projects usually involve specialized equipment, savings estimates should be assessed accordingly. It is expected that custom projects will incorporate professional project specific assessment of the savings. This assessment would serve as the primary documentation for a claim that savings exist.

A special assessment program should be implemented for the evaluation of custom projects. The assessment should be conducted on a random sample consisting of 10% of the large custom projects; and the projects should represent at least 10% of the total volume savings of all custom projects. The minimum number of projects to assess should be 5. Where less than 5 custom projects have been undertaken, all projects should be assessed. The assessment should focus on verifying the equipment installation and estimates of savings and equipment cost.

Custom projects should be audited using the same principles as any other program. Audit activities should be sufficient for the auditor to form an opinion on the overall LRAM, SSM and other financial incentives proposed in the Evaluation Report.

6.2.4 Market Transformation Programs

For each market transformation program the distributor should, in its DSM plan, propose a program description, goals (including specific metrics and measurement method), shareholder financial incentives (including structure and payment based on specific metrics), length, level of funding and program elements. Such programs are not amenable to a formulaic approach and therefore should be assessed on their own merits and all of the above components should be suitable given the subject matter and program goals.

6.2.5 Low Income Customer Programs

For each low income customer program the distributor should, in its DSM plan, propose a program description, goals (including specific metrics and measurement method), eligibility criteria, shareholder financial incentives (including structure and payment based on specific metrics), length, level of funding and program elements.

6.3 Implementation of Updated Input Assumptions

The input assumptions used to screen DSM technologies and programs may change over time due to more accurate and up-to-date information. The timing at which changes in assumptions become effective will differ depending on the use of the assumption, as follows:

Program Design and Implementation

> Utilities should design, screen and evaluate programs using the best available information known to them at the relevant time. Therefore, it is expected that utilities will incorporate new information into program design and implementation as soon as available. In considering the prudence of any spending in excess of an approved budget that has been tracked in a DSM variance account, it is expected that the information available to the distributor at the time the program was implemented will be considered. That is, when amounts in a DSM variance account are being reviewed for the purposes of disposition, it is expected that the information available to the distributor at the time the spending decision was made by the distributor will be considered. This will apply even if the input assumptions have changed since that time.

SSM

> The distributor should use the Board approved Input Assumptions for calculation of TRC for SSM purposes. This provides distributors the certainty needed to make prudent business decisions without having the goalposts moved after the fact. Assumptions used from the beginning of any year will be those assumptions in existence in the immediately prior year, adjusted for any changes in the audit of that prior year. By way of

example, if in June of 2008 the audit of the 2007 programs demonstrates a change in assumptions, that change shall apply for SSM purposes from the beginning of 2008 onwards until changed again

LRAM

The input assumptions used for the calculation of LRAM should be the best available at the time of the independent third party review referred to in section 6.5 below.

For example, if any input assumptions change in any given year, those changes should apply for LRAM purposes from the beginning of that year onwards until changed again.

Assume a program was delivered from January 1, 2007 until December 31, 2007. In June 2007, it was determined that the free rider rate used in the initial program analysis was under-stated. The distributor obtains a third party review of its evaluation of program results in April 2008. The input assumptions that will apply in relation to any lost revenue between January 1, 2007 and December 31, 2007, will be those that were introduced in June 2007. That is, the new free rider rates apply for the entire period from January 1, 2007 to December 31, 2007.

Best available information for the purposes of LRAM is that information available to the distributor immediately prior to the commencement of the audit by the independent third party.

6.4 Evaluation Report

A distributor that makes an LRAM, SSM or other financial incentive claim will need to file a detailed Evaluation Report at the time of making that claim. The Evaluation

Report should consist of the following sections:

Introduction

In the "Introduction" section of the Evaluation Report, utilities should provide a general overview of their DSM initiatives including any relevant local context.

Evaluation of the DSM Plan

This section should provide an overview of the effectiveness of a distributor's DSM plan. Utilities should report on all initiatives worked on and detail the process and impact analysis of the individual programs.

Note:

Stand alone education or marketing programs that do not have quantifiable benefits should report all relevant information (potential assessment criteria are identified in section 6.2.2). Marketing or support programs (i.e., programs designed to enhance market acceptance of other programs) should not be reported individually as they are components of other programs. Rather, the costs of marketing or support programs should be allocated to the programs they support.

Utilities who have pilot programs (see section 2.6), or other programs for which cost effectiveness data has not been provided by the Board (on the Board's website) should provide their own values, if available, and report all relevant information (attach a separate table if needed).

If the inputs and assumptions used by the distributor vary from those that have been posted on the Board's website, the variation(s) should be identified, and additional information supporting the variation(s) should be filed. If the specific technology promoted by a distributor was not included by the Board (on the Board's website), the distributor may select a similar technology as a proxy for annual reporting purposes. A distributor that selects a proxy technology for reporting should identify the actual technology in its Evaluation Report and the similarities between the proxy technology and the actual technology. However, for the purposes of a claim for recovery of LRAM, SSM or other financial incentives, where a distributor uses a proxy technology, the distributor should provide detailed evidence justifying the appropriateness of using the proxy technology, and detail the steps the distributor has taken, or will take, to determine the actual data for the technology used in the DSM program.

Lessons Learned

In the "Lessons Learned" section the distributor should indicate what has been learned over the course of the program. The goal of this section is to evaluate and benchmark programs for greater efficiency in delivery and cost effectiveness, and to provide information to other utilities with respect to DSM programs. Utilities should indicate if a program is considered a success or not and whether the program should be continued.

(4) Conclusion

The "Conclusion" section should consist of the distributor's summary of its performance relative to the DSM plan approved by the Board.

6.5 Independent Third Party Review

Given the rate-making implications of program evaluations, the Board and all relevant stakeholders need to be confident that evaluations are an accurate reflection of actual program results.

Section 2.1.12 of the Natural Gas Reporting & Record Keeping Requirements (RRR) Rule for Gas Utilities includes the timing requirements for annual audited DSM results.

The third party, although hired by the distributor, should be independent and will ultimately serve to protect the interests of ratepayers. Utilities should ensure that DSM budgets and spending include adequate funding to procure the third party review.

The third party is expected to:

- Provide an opinion on the cost effectiveness results that are material to the LRAM, SSM and other financial incentives proposed;
- Verify the results in the Evaluation Report to the extent necessary to give that opinion
- Confirm that the Board Approved input assumptions have been used. Where any input assumptions not on the Board approved list were used, provide an opinion on reasonableness of the assumption;
- Where the distributor has varied from the Board approved input assumptions , review the reasonableness of the input assumptions used;
- Recommend any forward looking evaluation work to be considered; and
- Recommend any relevant program improvement suggestions.

7.0 DSM CONSULTATIVE

Distributors should engage and seek advice from a variety of stakeholders and experts in the development and operation of their DSM programs as they consider appropriate. Given that the distributor can benefit by generating more TRC from its program portfolio, there is a natural interest to solicit input from those stakeholders that may bring value to the DSM program portfolio.

It is expected that each distributor will hold, at a minimum, two DSM Consultative meetings annually. All intervenors in the distributor’s most recent rate case should be invited to participate in these DSM Consultative meetings. The purpose of the meetings should be to:

- Review annual results (the Evaluation Report should be sent to the Consultative annually for review)
- Select an Evaluation and Audit Committee (EAC). Three members should be selected using the current process for selecting the Audit Sub-Committee; the fourth member will be the distributor. In the current process, the members of the consultative nominate individuals to stand on the committee. Then each member of the consultative votes for the three

members they would like on the committee. The three members with the highest number of votes are selected to the committee.

- Review the completed evaluation results

The EAC should provide formal input into the distributor's Evaluation Plan. In regards to evaluation activities, the EAC should have an advisory role in relation to the matters listed below:

- Consultation prior to the filing of the DSM plan on evaluation priorities over the lifetime of the plan

- Review and comment on evaluation study designs.

- Reviewing the scope and results of evaluation work completed on new programs introduced over the course of the DSM plan

- Selection of the independent auditor to audit the Evaluation Report and determine the scope of the audit. The EAC should ensure that all comments on the Evaluation Report that arise from the DSM Consultative meetings are reviewed by the auditor.

- Following the audit, review the evaluation plan annually to advise the Company on the scope and priority of identified evaluation projects.

Distributors, in consultation with the DSM Consultative, are expected to develop clear terms of reference regarding the role and operation of the DSM Consultative and EAC.

The distributor should determine, as part of the planning process, the appropriate amount to include in its overall DSM budget for stakeholder engagement, based on anticipated needs.

8.0 ACCOUNTING TREATMENT

8.1 Funding of DSM Programs

There could be two potential streams of funding available to distributors for the delivery of DSM programs: funding through distribution rates and funding from third parties.

Should an alternative source of funding become available for a program which was funded through distribution rates, the distributor should apply for that funding. In such circumstances, the DSM variance account should track the funding which was originally included in the distribution rates, so that it may be returned to ratepayers.

8.2 Cost Allocation

Utilities should use a fully allocated costing methodology for all third party funded DSM activities. Capitalized assets associated with DSM activities that are funded through rates will be included in rate base, and will be treated in the same manner as distribution assets. Assets purchased with funds from third parties will not be eligible for inclusion in rate base, nor will any ongoing operating costs associated with the asset, or income taxes payable in relation to third-party funded activities. The accounting treatment of DSM spending not funded through distribution rates is discussed in section 8.6 below.

Where funding is coming from a third party, the separation in costs will appropriately establish distribution rates by eliminating any cross subsidization between third-party funded DSM activities, and those activities funded through distribution rates. Where the funding would be from the distributor's rates, marginal costing will ensure that there is an appropriate basis to determine the cost effectiveness of DSM programs.

Cost allocation in rates should be on the same basis as budgeted DSM spending by customer class. This allocation applies to both direct and indirect DSM program costs.

8.3 Revenue Allocation

Any net revenues generated by a shareholder incentive for distribution rate-funded DSM should be separate from (i.e., not used to offset) the distributor's distribution revenue requirement.

Revenue earned from undertaking DSM funded by a third party shall also be treated on a fully allocated basis and separately from distribution revenues generated from ratepayer funded initiatives.

8.4 Demand Side Management Variance Account (DSMVA)

The rules around the DSMVA are as outlined in Section 3.2.

The distributor should apply annually to clear DSMVA amounts, subject to review as a component of the DSM audit, to ensure compliance with the Board approved rules..

Utilities should allocate the DSMVA amounts in rates based on their DSM spending variance for that year versus budget, by customer class. The actual amount of the variance versus budget targeted to each customer class should be allocated to that customer class for rate recovery purposes.

8.5 Carbon Dioxide Offset Credits Deferral Account (CDOCDA)

The CDOCDA was introduced by the OEB in the Generic Hearing and was developed to record amounts which represent proceeds resulting from the sale of or other dealings in earned carbon dioxide offset credits. There have not been any entries in this account since its inception. Now is the time to provide an incentive to distributors to create business opportunities to help customers manage carbon dioxide emissions.

Based on the right business incentives, distributors may have the ability to develop business offerings to work with customers to manage emission commitments. The CDOCDA is to be removed in order to provide distributors an opportunity to make this a profitable part of their business. This is consistent with the incentive regulation principle of minimizing deferral accounts. Through the current incentive regulation earning sharing mechanism, there is an inherent opportunity for ratepayers to benefits from this business opportunity should it become successful.

8.6 Recording of DSM Spending Not Funded Through Distribution Rates

Third-party funded DSM programs are classified as non-distribution activities. Consequently, the financial records associated with third-party funded DSM should be separate from those associated with the distributor's distribution activities.

A distributor receiving third-party DSM revenues and incurring related DSM expenses and/or capital expenditures should record these transactions in separate non-distribution accounts in the Uniform System of Accounts for Gas Utilities. For this purpose, account 312, Non-Gas Operating Revenue, should be used for revenues and account 313, Non-Gas Operating Expense, should be used for expenses. Sub-accounts may be used as appropriate.

9.0 ANNUAL REPORTING GUIDELINES

The guidelines set out in this section relate only to DSM programs funded through distribution rates.

Reporting on the progress and success of DSM programs is critical to maintaining accountability and transparency. For programs funded through distribution rates, utilities should file annual reports, by June 30 of each year as required by section 2.1.12 of the Natural Gas Reporting & Record Keeping Requirements Rule for Gas Utilities. Where utilities have approved funding for more than one year, a report should be filed annually summarizing the results of the previous year, and at the end of the plan term, addressing results for the entire plan term.

If the Board has approved DSM plans that span more than one year, annual reporting will be an important tool to allow the Board and stakeholders to monitor utilities' year-over-year progress in the implementation of their DSM plans. The annual report should provide the Board and stakeholders with information on what DSM activities the distributor is undertaking, how it is performing, what it is costing, and the distributor's planned future activities.

Where utilities have separate streams of funding, results should be differentiated in the Annual Report.

The Annual Report should consist of the following sections:

1. Introduction

In the “Introduction” section of the annual report, utilities should provide a general overview of their DSM initiatives including any relevant local context.

2. Description of the programs

In this section, the distributor should provide an overview of each program, including the targeted customer class or group, the objectives of the program, and any activities associated with the program.

3. Participation levels

In this section, distributors should detail the number of participants for each program.

4. Natural Gas savings in M^3_

In this section, distributors should provide the annual and cumulative energy savings attributable to each program, presented as both net and gross of free riders.

5. Measures evaluation research

In this section, distributors should describe any research completed regarding deemed savings assumptions and free rider and spillover estimates. The completed studies should be included as an appendix to the Annual Report.

6. LRAM statement

In this section, distributors should provide a statement that outlines the expected LRAM claim for the year of the Annual Report.

7. SSM and other incentives statement

In this section, distributors should provide a statement that outlines the expected SSM and other incentive claims for the year of the Annual Report.

8. Comments

In this section, distributors should provide any additional information as appropriate. This may include the distributor’s assessment of the success of the programs to date, what activities are planned for the subsequent year(s) (if applicable) and any planned modifications to program design or delivery.

10.0 ADMINISTRATION

10.1 Filing Guidelines (New)

This section contains the filing guidelines for the following types of applications:

10.1.1 - Program funding through distribution rates
10.1.2 - Lost Revenue Adjustment Mechanism
10.1.3 - Shared Savings Mechanism and other financial incentives
10.1.4 - Adjustments to an approved DSM plan

It is expected that utilities will comply with these filing guidelines as a minimum. Utilities should in all cases be prepared to demonstrate to the satisfaction of the Board that any given application should be approved, and are responsible for ensuring to that end that all relevant information is before the Board (including evidence that may have been filed in an earlier proceeding). Utilities are reminded that the Board may make any order or given any direction as the Board determines necessary concerning any matter raised in relation to any of the above applications, including in relation to the production of additional information which the Board on its own motion or at the request of a party considers appropriate.

10.1.1 Program Funding through Distribution Rates

An application for funding through distribution rates for new programs should include:

1. Characteristics of the applicant's distribution system, including:

- Total natural gas purchases;
- Sales by rate class; and
- Number of customers by rate class.

2. For each program, the following information should be provided:

- Detailed description of the program;
- Customer class(es) targeted;
- Projected incremental natural gas savings per year;
- Projected budget, listing:
- Description of the primary barriers to preventing higher uptake of the measures of the program
- Description of how the program will remove the barriers;

    - capital expenditures per year;
    - operating expenditures per year separated into direct and indirect expenditures;
    - for each direct operating expenditure, an allocation of the expenditure by targeted customer classes; and

- expenditures for evaluation of the program(s).

- Measure, programs and portfolio cost effectiveness results;

- The input assumptions underlying the forecasted savings and costs including a detailed presentation of the calculations;

- Where a program involves the implementation of specialized equipment or technology not identified in the list of inputs and assumptions as posted on the Board's website, the distributor should comply with the guidelines set out in 6.2.3 respecting custom projects;

- A statement as to whether the distributor has varied from the list of inputs and assumptions as posted on the Board's website. Where the distributor has varied from that list of inputs and assumptions, the distributor should provide detailed evidence to support the alternative data, including, at a minimum, a completed "Input Assumptions Template"; and

- The benefit-cost analysis, calculating the net present value of the initiative using the TRC test. For the purpose of calculating the net present value, a distributor should use a discount rate equal to the incremental after-tax cost of capital, based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity.

3. The distributor should also provide the following (specified on a per year basis):

- The total amount of DSM spending to be recovered in rates and the allocation of those costs to the customer class(es) that will benefit from the DSM program applied for;
- A forecast of the number of customers in each class and a forecast of M• of natural gas to be used as a charge determinant to determine the rate rider for each class to benefit from the DSM program; and
- A comparison of the proposed rates with and without the DSM rider for the rate year in question.

4. An Evaluation Plan, in accordance with section 6.1.

5. In addition to the information above, the following information should be provided for pilot programs (see section 2.6):

- A description of the technology being used;
- A discussion of whether and how, to the distributor's knowledge, the technology is being used or tested by any other utilities. Where the technology is being used by another distributor, a description of how the

distributor will coordinate or work with the other distributor using or testing the technology to ensure effective use of the program and of lessons learned; and

- The expected outcome of the pilot program. That is, what data or information will the program produce, and how will it be used for future DSM programs.

10.1.2 Lost Revenue Adjustment Mechanism (LRAM)

Section 4.0 contains information on the programs that are eligible for LRAM, the calculation of LRAM, and the timing of any application for recovery of LRAM.

An application for LRAM should include:

Third-Party Funded Programs

- Natural gas savings (both gross and net of free riders) for each program and for each class;
- The free rider rate applied to each program. Where different activities within a program have different free rider rates, the free rider rate for each activity should be provided;
- A calculation of the impact of the DSM program on distribution revenues in each class;
- Verification of the participation levels;
- Duration of the program in years or months;
- An Evaluation Report, in accordance with the guidelines set out in section 6.4; and
- Any reports completed by an independent third party, in accordance with the guidelines set out in section 6.5.

Programs Funded through Distribution Rates

- Natural gas savings (both gross and net of free riders) for each program and for each class;
- The free rider rate applied to each program. Where different activities within a program have different free rider rates, the free rider rate for each activity should be provided;
- A calculation of the impact of the DSM program on distribution revenues in each class;
- Verification of the participation levels;
- Where savings information is not provided in the list of inputs and assumptions posted on the Board's website. the distributor should comply with the guidelines set out in section 6.2.3 respecting custom projects;
- A statement as to whether the distributor has varied from the list of inputs and assumptions as posted on the Board's website. Where the distributor has varied from that list of inputs and assumptions, the distributor should

provide detailed evidence to support the alternative data, including, at a minimum, a completed "Input Assumptions Template"; and
- Duration of the program in years or months.

For programs funded in 2010 and beyond, the following information should be provided, in addition to the guidelines set out above:

- An Evaluation Report, in accordance with the guidelines set out in section 6.4; and
- All reports completed by an independent third party, in accordance with the guidelines set out in section 6.5.

All information filed in support of the LRAM claim should correspond to program information used in the calculation of the benefit-cost analysis.

10.1.3 Shared Savings Mechanism (SSM) and Other Financial Incentives

Section 5.0 contains information on the programs that are eligible for SSM and other financial incentives, the calculation of SSM and other incentives, and the timing of any application for recovery of SSM or other financial incentives.

An application for SSM or other financial incentives should include:

- Natural gas savings (both gross and net of free riders) for each program and for each class;
- The free rider rate applied to each program. Where different activities within a program have different free rider rates, the free rider rate for each activity should be provided;
- A calculation of the impact of the DSM program on distribution revenues in each class;
- Verification of the participation levels;
- Where savings information is not provided in the list of inputs and assumptions as posted on the Board's website, the distributor should comply with the guidelines set out in section 6.2.3 respecting custom projects;
- A statement as to whether the distributor has varied from the list of inputs and assumptions as posted on the Board's website. Where the distributor has varied from that list, the distributor should provide detailed evidence to support the alternative data, including, at a minimum, a completed "Input Assumptions Template;" and
- Duration of the program in years or months.

For programs funded in 2010 and beyond the following information should be provided in addition to the information set out above:

- An Evaluation Report, in accordance with the guidelines set out in section 6.4; and
- All reports completed by an independent third party, in accordance with the guidelines set out in section 6.5.

10.1.4 Adjustments to an Approved Plan

An application for adjustments to an approved multi-year DSM plan should occur only in exceptional circumstances. Any application for an amendment must meet a very high onus to demonstrate undue harm absent the application. Where such an application is made, it should include evidence to demonstrate the likelihood of undue harm in the absence of the application being made and any other supporting evidence.

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