**REVIEW OF DEMAND SIDE MANAGEMENT (DSM) FRAMEWORK FOR NATURAL GAS DISTRIBUTORS**

*Prepared for:*

The Ontario Energy Board

*March 19, 2010*

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## GLOSSARY OF TERMS

| | |
|---|---|
| AGA | American Gas Association |
| ACEEE | American Council for an Energy-Efficient Economy |
| BAT | Best Available Technologies |
| BCR | Benefit-Cost Ratio |
| CEA | Cost-Effectiveness Analysis |
| CGA | Canadian Gas Association |
| Commission | Public Utilities Commission or Public Service Commission |
| Concentric | Concentric Energy Advisors, Inc. |
| CWG | Conservation Working Group |
| DSM | Demand Side Management |
| DSM Framework | Board's Existing DSM Framework |
| Draft DSM Guidelines | Draft DSM Guidelines for Natural Gas Distributors |
| Enbridge | Enbridge Gas Distribution, Inc. |
| EAC | Evaluation and Audit Committee |
| GEA or the Act | Green Energy Act |
| GHG | Greenhouse Gas |
| LEAP | Low Income Energy Assistance Program |
| LRAM | Lost Revenue Adjustment Mechanism |
| NRRI | National Regulatory Research Institute |
| OEB or the Board | Ontario Energy Board |
| Ofgem | Office of Gas and Electricity Markets (Great Britain) |
| PAC test | Program Administrator Cost test |
| RFP | Request for Proposal |
| SSM | Shared Savings Mechanism |
| TRC test | Total Resource Cost test |
| Union | Union Gas Limited |
| U.S. | United States of America |

## EXECUTIVE SUMMARY

The Ontario Energy Board ("OEB" or the "Board") retained Concentric Energy Advisors, Inc. ("Concentric") to prepare a report that critically reviews, compares and assesses Ontario's Demand Side Management ("DSM") framework for natural gas distributors with respect to best practices in selected North American and other jurisdictions and to make recommendations on what changes, if any, should be made to the existing DSM framework for 2011 and beyond. Concentric's research indicates that Ontario's existing DSM framework compares favorably to many other jurisdictions that were reviewed for this report. However, opportunities remain for the OEB to make enhancements to the DSM framework in order to address issues raised by stakeholders and meet best regulatory practices for administering such programs.

This report examines DSM policies and frameworks that have been adopted by regulatory bodies in Canada, the United States, the Great Britain, Australia and New Zealand. While the primary focus is on natural gas distributors, Concentric also reviewed DSM policies and frameworks that have been implemented for electric providers in order to determine whether there are any lessons to be learned across industries, or any opportunities for synergies between DSM policies and frameworks for natural gas distributors and electric utilities.

Ontario's DSM policies and programs must adapt to changing market conditions in order to continue achieving conservation targets in an equitable, cost-effective and economically efficient manner. The OEB faces the challenge of how best to balance administrative costs (e.g., to screen programs, disseminate feedback, document processes and measure results) with the effort required to attain conservation targets and efficiency improvements. These are common themes among the more progressive jurisdictions, and initiatives have been launched to address these problems. Evaluating the successes and failures in these other jurisdictions will assist Ontario's effort to improve its own DSM framework.

Many utility regulatory bodies across Canada and the United States have opened proceedings to examine whether DSM policies and frameworks are achieving conservation objectives and whether energy efficiency should be a more important part of the regulatory approach to reducing carbon emissions and mitigating climate change. Due to this regulatory adaptation to shifting policy objectives, it is difficult to identify what may be considered "best practices" because these continue to evolve. Based on Concentric's research of other North American jurisdictions, it appears that the design and development of the DSM framework is increasingly dependent on the regulator's response to climate change and carbon emissions reduction, versus the more traditional focus on objectives such as energy efficiency, supply offsets, or low income assistance. For Ontario, a more aggressive stance toward climate change may justify a different DSM framework (or significant changes to input parameters), while a more traditional approach would suggest continuation of the existing policy, with minor modifications or adjustments.

The evaluation of a DSM Framework cannot be done in isolation from the over-arching policy objectives. At the heart of the matter is determining how best to meet the public interest, and there are actually a continuum of approaches that regulators might use to achieve the public interest based on their policy objectives for DSM programs. Concentric developed the following table to demonstrate how regulators in various jurisdictions might develop different DSM frameworks depending on their policy objectives.

**Table 1: Possible Regulatory Approaches to DSM**

| Regulatory Approach | Traditional | Progressive | Aggressive |
|---|---|---|---|
| Primary Objective | Energy Savings | Energy Savings<br>Manage Demand Growth | Energy Savings<br>Manage Demand Growth<br>Carbon Reduction |
| Cost Effectiveness Test | Ratepayer Impact<br>Utility Cost | TRC | Societal<br>Modified TRC |
| Avoided Costs | Commodity | Commodity/Capacity | Commodity/Capacity/ Externalities/Carbon reduction |
| Input Assumptions | Utility costs | Utility costs<br>Participant costs | Utility costs, participant costs<br>Externalities |
| Adjustment Factors | Free ridership<br>Persistence<br>Attribution | Plus free drivership,<br>Spillover and<br>Proportional attribution | Secondary concern<br>(tradeoff theory) |
| DSM Program Design | Prescriptive | Flexible | Proportional reduction |
| DSM Budget | Fixed $ Amount | % of Revenues | Objective/target Driven |
| DSM Metrics/Targets (Measuring Success) | Energy Saved/DSM $ | Short term and long term energy savings | Long term energy savings<br>Market Transformation<br>DSM Penetration<br>Carbon Reduction |
| Financial Incentive (Utilities) | Limited | Tied to Energy Savings | Tied to Societal Goals/Climate |
| Compensating for Lost Revenue | Minimal | LRAM | Revenue Decoupling |
| Conservation Impact Evaluation | Utility report, prudence review | Independent review and verification | Evaluate whether DSM results achieve program objectives |
| Filing and Reporting | Progress Report / Evaluation Report | Audited Program Results | Broad Evaluation Measures |
| Stakeholder Input | Limited/Informal | Formal/Advisory | Proactive Consultation<br>Direct Involvement |
| Integration of Gas/Electric | Limited/None | Encouraged | Mandated |

Given the policy direction from the Ontario provincial government, including the Green Energy Act, Concentric developed its recommendations based on our understanding that the OEB's current policy objectives for DSM programs include energy savings, demand growth management, and assisting low-income customers with managing energy costs, and most likely will include carbon emissions reduction consistent with government policy objectives. Specific recommendations include:

**Cost Effectiveness Tests**

- Adopt the Societal Cost test to measure cost effectiveness and overall program benefits, including environmental and social externalities; but use the Program Administrator Cost test to prioritize DSM programs;
- Apply the cost effectiveness test on a program basis, rather than a portfolio basis;

**Input Assumptions and Measures**

- Gas distributors should be responsible for calculating avoided costs using a limited number of input assumptions, including the commodity cost, capital costs, and operating and maintenance expenses;
- Adopt a societal discount rate based on the average yield on the Government of Canada long bond rather than the utility's after-tax weighted average cost of capital;
- Coordinate with the Ministry of Energy and Infrastructure to establish a value for carbon emissions to be included in calculating avoided costs;
- Continue to develop a common set of input assumptions, which are updated annually to reflect the best available information based on the Evaluation Reports;
- Assume that free ridership is offset by spillover, unless a specific program can be reliably shown to deviate from this assumption, or multiply reported energy savings by a designated factor to adjust for the effects that are not attributable to DSM;
- Alternatively, rely on empirical data from the annual Evaluation Reports or on evidence from other jurisdictions to establish free ridership percentages;
- Assign a percentage of credit to the utility based on the percentage of total dollars they spent on designing, developing and delivering the joint DSM programs. Utilities wishing to deviate from the percentage would be required to provide supporting evidence;

- Persistence should be determined based on the technical input assumptions and the annual Evaluation Reports; it should not be assumed to be 100%;
- DSM programs should be designed to emphasize those measures and technologies which contribute most to cost effective energy savings; the market potential studies should guide the Board in approving programs with identified energy savings opportunities or which are aligned with known "behavioral" problems;
- Utilize a combination of customer and vendor surveys to estimate the effectiveness of market transformation programs, with the understanding that precise estimates are not attainable;

**Low Income Customers**

- DSM programs for low-income customer should follow several guiding principles including identifying geographic areas with the highest concentration of low-income customers, focusing on those customers with the highest energy use and a history or late payments or disconnections, developing programs that serve an entire neighborhood rather an individual customer, concentrate on programs that provide an immediate long-term benefit, coordinating with community organizations and local contractors to modify behavior and attitudes, and understanding the unique challenges of serving this market;
- Separately evaluate cost effectiveness of DSM programs for low-income consumers, using the Societal Cost test with a lower threshold in the range of 0.60 to 0.75;
- For low income programs, develop a separate financial incentive mechanism that is contingent on market penetration, reductions in gas consumption per customer, and efforts to reduce customer bills through education and awareness programs;

**Budgets and Incentives**

- Increase recommended spending on DSM programs in Ontario to between 4% and 6% of utility operating revenues less the cost of purchased gas, and establish a minimum spending level equal to at least 3% of utility operating revenues less the cost of purchase gas;
- Allow gas distributors flexibility in proposing budgets to meet the DSM metrics and targets because the utilities are in the best position to determine which programs will be most effective;

- Consider more extensive review of those programs that account for the majority of expenditures and savings, and that smaller programs be subject to less rigorous or less frequent scrutiny.
- Limit the amount of the budget that is spent on evaluating and monitoring DSM programs to between 3% and 5% of the total budget for each gas distributor;
- Adopt market penetration of Best Available Technologies[1] as the primary metric to measure the success of individual DSM programs and measures, and the percentage reduction in gas consumption per customer as the secondary metric when market penetration is not applicable;
- Revise the financial incentive calculation to place more emphasis on market penetration and percentage reduction in gas consumption per customer;
- Reward gas distributors with financial incentives only if they exceed the targets for the established metrics;
- For purposes of calculating financial incentives, use best available information for input assumptions, which are updated annually based on the Evaluation Reports;

**Revenue Recovery**

- Allow gas distributors to request revenue decoupling to recover lost revenues attributable to DSM programs;
- If the Board continues to use the Lost Revenue Adjustment Mechanism ("LRAM"), it should include best available information for the input assumptions, but the Board should establish a date by which information must be submitted to calculate the LRAM;

**Program Evaluation, Stakeholder Input and Relation to Electric Programs**

- The Board should appoint the entities responsible for conducting the independent program evaluation and the third-party audit of program results;

[1] The term "Best Available Technology", or "BAT", is borrowed from the term embodied in air pollution regulations, which set standards based on the best available control technology. The advantage of such guidelines is that they establish an objective measure of compliance with the standard. Used in the context proposed here, Concentric is suggesting that DSM programs be measured against objective measures. For example, if the best available technology for residential boilers is 80% efficient, then penetration of 80% efficient boilers becomes the standard of measurement. These standards may be established through proposals by the utilities, and verified by technical consultants, or through open-source databases such as those used in California.

- Adopt the proposed annual reporting and evaluation reporting requirements as described in the Draft DSM Guidelines;
- Continue to solicit stakeholder input in the manner prescribed by the existing DSM Framework;
- Encourage gas and electric utilities in Ontario to cooperate on the delivery of DSM programs, whenever possible, and consider ways in which gas and electric utilities might coordinate their efforts to improve customer participation and achieve administrative efficiencies.

## I. Introduction and Purpose

The OEB retained Concentric to critically review, compare and assess Ontario's DSM framework for natural gas distributors with respect to best practices in selected North American and other jurisdictions and to make recommendations on what changes, if any, should be made to the DSM Framework. In its Request for Proposal ("RFP"), the Board listed fourteen critical elements that were identified by stakeholders, and which the Board wished to examine as part of this comparative review of the existing DSM Framework in Ontario.

1. Cost effectiveness test
2. Estimation and use of avoided costs
3. Development and use of input assumptions for evaluating DSM technologies
4. Adjustment Factors for assessing impacts of DSM programs
5. Design of DSM Programs for different market segments
6. DSM budget development and approval process
7. Development of DSM metrics and targets
8. Shareholder incentive mechanism
9. Lost Revenue Adjustment Mechanism (LRAM)
10. Conservation program impact evaluation methods
11. Filing and reporting requirements
12. Stakeholder input and consultation process
13. Integration of natural gas and electricity conservation programs
14. Whether to replace existing DSM framework with a fundamentally different framework

For each of the fourteen DSM Framework elements listed above, this report:

- Reviews the existing DSM Framework for natural gas distributors in Ontario, as established in the 2006 generic DSM proceeding (EB-2006-0021);
- Reviews stakeholder comments in response to the *Draft Demand Side Management Guidelines for Natural Gas Distributors* in EB-2008-0346 and from the Conservation Working Group (as part of EB-2008-0150), as well as Board reports and decisions issued in the original 1993 DSM proceeding (EBO 169-III), the 2006 generic DSM proceeding and the Consultation on Energy Issues Relating to Low-Income Consumers (EB-2008-0150);
- Comparatively reviews best practices in North America (Canada and the United States) and other international jurisdictions (England, New Zealand, and Australia);
- For each jurisdiction reviewed, describes the legal and regulatory context in which DSM programs operate; and
- Recommends what changes could be made to improve Ontario's overall natural gas DSM framework and each of its elements.

## II. ORGANIZATION OF THE REPORT

Section III describes our research methodology. Section IV provides our analytical framework for determining "best practices" in evaluating the regulatory approach to DSM taken in different jurisdictions. Section V outlines the evaluation criteria that were used in deriving our recommendations. Section VI discusses the history and current status of DSM activities in Ontario and summarizes the key elements of the Green Energy Act as it relates to energy efficiency and conservation and the provincial targets for reducing carbon emissions. Section VII presents an overview of natural gas DSM policies and programs in Canada and the United States based on a review of recent literature from a variety of different organizations. Sections XIII through XXI correspond to the fourteen critical elements of the existing DSM Framework in Ontario. Each section: a) describes Ontario's existing DSM policy and framework[2]; b) summarizes the stakeholder

[2] Except as otherwise noted, this information was taken from the Board's decisions in the 2006 generic DSM proceeding (EB-2006-0021). In several places, the OEB staff has proposed additions or modifications to the existing DSM framework, as described in the *Draft Demand Side Management Guidelines for Natural Gas Distributors* ("Draft DSM Guidelines") issued on January 26, 2009 in EB-2008-0346.

comments regarding the current DSM policy[3]; c) examines how other jurisdictions handle these issues and compares those approaches to what has been done in Ontario; and d) makes recommendations to either continue with the current DSM framework or to enhance it consistent with "best practices." Appendix A contains an overview of DSM programs and measures in the U.S. states included in our research.

## III. RESEARCH METHODOLOGY

Concentric's research included both primary and secondary sources of information. We examined the DSM policies and programs in 20 different jurisdictions – five Canadian provinces, twelve U.S. states, and three countries outside North America. Our research revealed that regulators in three of the five Canadian provinces, eleven of the twelve U.S. states, and two of the three foreign countries had adopted formal DSM requirements and policies for natural gas distributors. Our primary research sources included Board/Commission websites, Board/Commission orders and rules, and gas utility program filings and descriptions. The following jurisdictions were initially included in this study:

**Table 2: Jurisdictions Included in Concentric Study**

| Canadian Provinces | U.S. States | Other Countries |
|---|---|---|
| Alberta* | California | Great Britain |
| British Columbia | Colorado | New Zealand* |
| Manitoba | Connecticut | Australia* |
| Nova Scotia* | Iowa | |
| Quebec | Maine | |
| | Massachusetts | |
| | Minnesota | |
| | New Jersey | |
| | New York | |
| | Oregon | |
| | Washington* | |
| | Wisconsin | |

3 This includes stakeholder comments that were filed in response to the Draft DSM Guidelines, as well as comments from the Low Income Energy Assistance Program ("LEAP") report issued in March 2009 in EB-2008-0150 and from the Conservation Working Group which was established by the Board to develop recommendations for DSM policies to serve low-income customers.

* Has not adopted formal DSM framework for gas distributors.

Jurisdictions in the U.S. were chosen because they were determined to be states which had the highest per capita spending on gas DSM programs.[4] Jurisdictions in Canada were selected because they were known to have gas distributors that were actively engaged in DSM activities. The three foreign countries were chosen to provide additional perspective from outside North America.

Secondary research sources included publications sponsored by the Canadian Gas Association, or undertaken by the American Gas Association ("AGA"), the American Council for an Energy-Efficient Economy ("ACEEE"), the National Regulatory Research Institute ("NRRI"), and a group of environmental and energy conservation experts for the National Energy Service Conference and Expo. Concentric also reviewed the 2009 Green Energy Act and the Environmental Commissioner's report on progress toward achieving Ontario's carbon emission reduction goals.

## IV. Defining "Best Practices"

The term "best practices" has a variety of different definitions. For purposes of this report, Concentric found it useful to think about best practices in terms of the regulator's perspective concerning government policy objectives regarding energy efficiency, conservation activities, renewable energy, environmental externalities, and greenhouse gas emission reductions. In that regard, the framework proposed by Dr. Keeler of Ohio State University (in conjunction with the NRRI) was particularly instructive. Dr. Keeler discusses the ways in which state Commissions approach climate change[5] and provides a framework around different definitions of the public interest, dividing possible regulatory approaches into three categories as follows:

1) One version of the public interest is that of an *activist* Commission that incorporates overall collective attitudes and goals toward GHG reduction into its decision-making (and not just the letter of the law as expressed in current policy). Commissioners would be motivated by a belief that reducing GHGs is in and of itself an essential part of the public interest. Such a Commission would still balance cost and reliability

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4 The benefit of this sample is that states which spend more on gas DSM programs are likely to have gained more experience in terms of designing a regulatory framework that contributes to the success of energy efficiency.

5 "Climate Change and State Utility Commissions: What is the Public Interest?," Ohio State University, John Glenn School of Public Affairs, Dr. Andy Keeler, November 2008, at 2-3.

with GHG emissions in making policy and specific decisions, but would view GHG reduction as a goal rather than a constraint.

2) The second version is that of an *efficient* Commission – one that takes GHG reduction goals as given by legislative and other policy-making bodies, but attempts to meet those goals in ways that minimize costs to the overall economy over time, rather than the way that best meets the goals of low rates and reliable supply. This approach is consistent with a view that regulation should work toward correcting imperfect markets so that they carry information and coordinate choices that maximize economic productivity and welfare.

3) The third version is that of a *traditional* Commission, which takes GHG reduction goals as given by legislative and other policy-making bodies and seeks to meet the twin goals of low rates and reliable supply. Low rates are not always consistent with maximum GHG reduction, and can also be at odds with efficiency. Commissions have traditionally viewed ensuring low rates as the central aspect of consumer protection, and there has been substantial political support from consumer advocacy institutions.

Dr. Keeler notes that utility regulators have generally defined the public interest as achieving the best possible tradeoff between low rates and reliable supply, while meeting environmental goals has been treated as a constraint. However, climate change poses a different challenge than have traditional forms of environmental regulation. The article offers several examples which are relevant to the current situation in Ontario. Specifically, the author discusses how different utility regulators might approach a request to construct new coal-fired generation. Activist commissions will tend to oppose any new conventional coal generation on the grounds that carbon capture and storage-compatible coal generation or other sources are more consistent with the collective responsibility to reduce climate change risks. Efficient commissions will tend to base their assessment on their expectation about future climate policy and the resulting carbon price: the higher the expected price, the less likely they are to view conventional coal as an efficient choice. Traditional commissions might base their decision on whether the construction of new generation will bring about no-cost allowance allocations or other policies designed to protect consumers of higher-GHG energy.[6]

[6] Ibid, at 3.

A second illustration relates to how these views apply to the issue of ratemaking and allowance allocation. An activist commission would tend to seek to use the value of allowances for investments in GHG reduction – through demand side management or subsidization/investment in low GHG energy. An efficient commission would argue for passing the full marginal cost of GHG allowances to all consumers in order to achieve the lowest-cost combination of generation and end-use reduction – which implies passing through the marginal cost of GHG allowances to customers. A traditional commission would try to use allowance value to keep end-user prices as low as possible by applying that allowance value to reducing the revenue requirement.[7]

Ontario's position on energy efficiency, conservation and renewable energy, as evidenced by the recent passage of the Green Energy Act and the government focus to reduce GHG emissions, suggests that the Board is likely to adopt policies similar to those characterized as "efficient", if not "activist" along this spectrum. Therefore, the analyses and recommendations contained in this report reflect that anticipated direction in policy. However, the extent of this shift will become more apparent, and the policy environment will become clearer, once the broad policy objectives of the Green Energy Act are more fully deliberated.

Concentric's research of other North American jurisdictions indicates that the design and development of the DSM framework is increasingly dependent on the regulator's response to climate change and carbon emissions reduction, versus the more traditional focus on objectives such as energy efficiency, supply offsets, or low income assistance. For Ontario, a more aggressive stance toward climate change may justify a different DSM framework (or significant changes to input parameters), while a more traditional approach would suggest continuation of the existing policy, with minor modifications or adjustments.

The evaluation of a DSM Framework cannot be done in isolation from the over-arching policy objectives. At the heart of the matter is determining how best to meet the public interest, and there are actually a continuum of approaches that regulators might use to achieve the public interest based on their policy objectives for DSM programs.[8] Concentric developed the following table to

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7 Ibid, at 4.

8 Concentric credits the work of Dr. Andy Keeler with Ohio State University, and his paper published under the auspices of the National Regulatory Research Institute, for his writings on this topic.

demonstrate how regulators in various jurisdictions might develop different DSM frameworks depending on their policy objectives.

**Table 3: Possible Regulatory Approaches to DSM**

| Regulatory Approach | Traditional | Progressive | Aggressive |
|---|---|---|---|
| Primary Objective | Energy Savings | Energy Savings<br>Manage Demand Growth | Energy Savings<br>Manage Demand Growth<br>Carbon Reduction |
| Cost Effectiveness Test | Ratepayer Impact<br>Utility Cost | TRC | Societal<br>Modified TRC |
| Avoided Costs | Commodity | Commodity/Capacity | Commodity/Capacity/<br>Externalities/Carbon reduction |
| Input Assumptions | Utility costs | Utility costs<br>Participant costs | Utility costs, participant costs<br>Externalities |
| Adjustment Factors | Free ridership<br>Persistence<br>Attribution | Plus free drivership,<br>Spillover and<br>Proportional attribution | Secondary concern<br>(tradeoff theory) |
| DSM Program Design | Prescriptive | Flexible | Proportional reduction |
| DSM Budget | Fixed $ Amount | % of Revenues | Objective/target Driven |
| DSM Metrics/Targets (Measuring Success) | Energy Saved/DSM $ | Short term and long term energy savings | Long term energy savings<br>Market Transformation<br>DSM Penetration<br>Carbon Reduction |
| Financial Incentive (Utilities) | Limited | Tied to Energy Savings | Tied to Societal Goals/Climate |
| Compensating for Lost Revenue | Minimal | LRAM | Revenue Decoupling |
| Conservation Impact Evaluation | Utility report, prudence review | Independent review and verification | Evaluate whether DSM results achieve program objectives |
| Filing and Reporting | Progress Report / Evaluation Report | Audited Program Results | Broad Evaluation Measures |
| Stakeholder Input | Limited/Informal | Formal/Advisory | Proactive Consultation<br>Direct Involvement |
| Integration of Gas/Electric | Limited/None | Encouraged | Mandated |

## V. EVALUATION CRITERIA FOR RECOMMENDATIONS

Concentric's recommendations will generally fall into two broad categories. On the one hand, we will make specific recommendations on issues where there appear to be gaps between industry best practices and the existing (or proposed) DSM framework in Ontario. Alternatively, we will specify where policy decisions must be made by the Board, and will suggest direction among the various options based on our understanding and interpretation of Ontario's provincial policies on energy and the environment.

Before making our recommendations, Concentric believes it is important to describe the guiding principles which we used to arrive at our ultimate recommendations.

- Define Program Objectives: The DSM framework should be designed consistent with policy objectives and the public interest. The regulatory approach to DSM programs is most likely different in a jurisdiction where energy conservation is the primary policy objective than one in which reducing carbon emissions or addressing fuel poverty are the policy objectives. In other words, the appropriate DSM framework is largely a function of the stated program goals for energy efficiency.

- Comprehensive Policy Approach: The DSM framework should be designed as a comprehensive policy approach to achieving energy efficiency and conservation goals. Although this report is divided into fourteen individual components, from Concentric's perspective, these fourteen elements are interdependent and should not be viewed in isolation. That is, the ultimate policy approach in Ontario should recognize that changes to one element will almost always necessitate changes to other elements as well.

- Inclusion of Externalities: The DSM framework should acknowledge the trend toward inclusion of environmental and social externalities in the cost effectiveness test. If the regulatory approach is focused on anything more than reducing gas consumption or load management, then the cost-benefit analysis should be modified to allow consideration of externalities.

- Establish Benchmarks: The DSM framework should require gas distributors to gather information regarding the current situation in Ontario. In order for utilities to design effective DSM programs, the Board must have baseline information against which it can measure progress. This benchmarking would involve measuring the existing capital stock in Ontario and identifying gaps between that capital stock and the Best Available Technology ("BAT").

- Align Program Objectives with Spending: The DSM framework should result in approval of those DSM programs and measures which are most cost effective and which achieve market penetration goals. The Board should rely on the selected cost effectiveness test to choose DSM programs and measures with the highest net savings, and should direct gas distributors to develop and propose energy efficiency programs that achieve maximum economic penetration.

- Ability to Measure Results: The DSM framework should enable the Board to reliably measure and verify program results. The Board should consider whether it could achieve this goal by concentrating on market penetration; that is, by establishing target percentages for replacing existing technologies with the BAT.

- Keep it simple: The DSM framework should be relatively straight-forward and easily understandable. The Board should consider whether increased complexity results in higher precision, or whether it simply leads to more time and money spent measuring and debating program results.

- Build Trust: The DSM framework should be designed to enhance confidence among stakeholders that program results are accurately measured and clearly reported. The Board should strive to make regulation as transparent as possible so that everyone understands the purpose of the program, the mechanics of the program, and the rules and standards the Board will use to evaluate and measure success.

Finally, Concentric believes it is important for the OEB to set forth well-articulated policy objectives for its energy efficiency and conservation program. If Ontario is going to remain a leader in developing and implementing DSM programs, Concentric believes that it will be necessary for all stakeholders to remain cognizant of the public interest and to adopt a common societal purpose. The Province's objectives for energy efficiency and climate change are ambitious, and will require all stakeholders to cooperate in the interest of attaining the most successful DSM program possible. The Board can provide leadership by developing a DSM framework that sets well-defined program objectives, allows gas distributors some flexibility in designing and delivering cost effective programs that achieve the stated targets, rewards utilities for achieving verified success and compensates them for lost revenues, and requires independent oversight and regulatory monitoring of program results.

Based on these evaluation criteria, the following figure summarizes the current DSM framework in Ontario and Concentric's recommended DSM framework, based on our application of industry "best practices" to the specific circumstances in Ontario.

## Recommended Changes to the OEB DSM Framework[1]

| | Current | Recommended |
|---|---|---|
| Cost Effectiveness Test | Total Resource Cost Test | Societal Cost Test |
| Program Prioritization | Total Resource Cost Test | Program Administrator Cost Test |
| Low Income Screen | Modified TRC | Modified TRC (lower threshold) |
| Key Program Measurement | Net TRC Savings | Market Penetration of BAT |
| Revenue Recovery | LRAM | Decoupling |
| Incentive Clause | Graduated SSM | SSM For exceeding targets |
| DSM Budget | Approximately 3% of utility revenues | 4% - 6% of utility revenues |
| Program Evaluation | Evaluators & auditors selected by utilities | Evaluators & auditors appointed by Board |
| SSM Incentive | Locked-in assumptions | Best available information |

[1] This information was taken from the Board's decisions in the 2006 generic DSM proceeding (EB-2006-0021). In several places, the OEB staff has proposed additions or modifications to the existing DSM framework, as described in the *Draft Demand Side Management Guidelines for Natural Gas Distributors* ("Draft DSM Guidelines") issued on January 26, 2009 in EB-2008-0346.

## VI. History and Current Status of the DSM Framework in Ontario

Over the past two decades, the Board has articulated policies and regulatory requirements in relation to natural gas distributor DSM activities. The Board established the original regulatory framework for distributor sponsored DSM programs in July 1993.[9] Union Gas Limited ("Union") and Enbridge Gas Distribution, Inc. ("Enbridge") filed DSM plans in accordance with that framework until 2006.

In 2006, the OEB conducted a hearing on generic issues related to natural gas distributor's DSM activities.[10] The Board's August 2006 decision in Phase I of the generic proceeding set out the framework for natural gas DSM.[11] In a separate October 2006 decision in Phase II of the same

[9] *See* Ontario Energy Board, EBO 169-III Report of the Board, July 23, 1993.

[10] *See* Ontario Energy Board, EB-2006-0021

[11] Interested stakeholders were invited to register as intervenors and actively participate in the proceeding. Registered intervenors included several environmental and ratepayer groups, including some that represent low-income consumers.

As a first step, a list of issues to be examined was developed and agreed upon with input from both the utilities and the intervenors. Next, a "Technical Conference" was held whereby both the utilities and registered intervenors could file evidence and question each other on the evidence filed.

A "Settlement Conference" was then held with the objective of reaching a settlement or agreement among the parties on as many issues as possible. The purpose of a settlement conference is to settle all the issues referred to the conference in a proceeding. Board members do not participate and are not advised of the admissions, concessions, offers to settle and related discussions that take place at the conference. A facilitator is appointed by the Board to chair the settlement conference and attempts to achieve a settlement of all issues or as many as possible. All registered parties in a proceeding can participate, but not the general public. Board staff attend the conference to ensure that all relevant information is brought forward and considered in negotiations, and endeavour to help the parties reach a settlement. Board staff do not sign the settlement proposal.

In the course of the proceeding, the Board was presented with three settlement agreements. The first was a complete settlement on some of the issues. The other two were partial settlements.

The first partial settlement contained issues that were settled as between Enbridge and Union on the one hand, and most of the intervenors on the other. Some of the issues in this package dealt with the financial issues and this "financial package" was considered by the parties to be unseverable. That is, the parties to this partial agreement regarded each of the elements of the package to be crucial to the package as a whole. Were the Board to disapprove of any discrete element of the package, the package as a whole would be withdrawn, and each of the elements would have to be litigated.

The second partial settlement contained proposals that were agreed to by all intervenors, but not the utilities.

The Board accepted the "financial package" and indicated that it was pleased that the package amounted to what is largely a "rules-based" approach.

The Board held an oral hearing to decide on the remaining issues.

proceeding, the Board approved the input assumptions which were used by Union and Enbridge in filing their three year DSM plans. Individual DSM plans were subsequently approved by the Board and were scheduled to expire in 2009.

In October 2008, the Board initiated a consultation process to develop DSM guidelines to be used by natural gas distributors in developing their next generation DSM plans.[12] The intent of the consultation was to develop a new framework that would replace that established through the 2006 generic DSM proceeding. Draft DSM Guidelines were developed and issued for stakeholder comment. In addition, the Board retained a consultant to produce a report updating the DSM technologies and input assumptions to be used by gas distributors. However, prior to finalization of the Guidelines, the Board issued a letter informing stakeholders that the consultation had been deferred in recognition of the potential impact that the Green Energy Act, 2009 could have on energy conservation programs and activities. In lieu of new guidelines, natural gas distributors were instructed to file DSM plans for 2010 using the existing DSM Framework as set out in the August 2006 decision in the generic proceeding, but using the new input assumptions developed as part of this proceeding.[13]

Based on stakeholder comments received on the draft DSM Guidelines, the Board identified fourteen elements related to the existing DSM framework that it wished to examine further. These included: 1) cost effectiveness test; 2) estimation and use of avoided costs; 3) development and use of input assumptions for evaluating DSM technologies; 4) adjustment factors for assessing impacts of DSM programs; 5) design of DSM programs for different market segments; 6) DSM budget development and approval process; 7) development of DSM metrics and targets; 8) shareholder incentive mechanism; 9) lost revenue adjustment mechanism; 10) conservation program impact evaluation methods; 11) filing and reporting requirements; 12) stakeholder input and consultation process; 13) integration of natural gas and electricity conservation programs; and 14) whether to replace existing DSM framework with a fundamentally different framework.

[12] *See* Ontario Energy Board, EB-2008-0346

[13] In January 2010, the Board subsequently extended the existing DSM Framework once again, and instructed natural gas distributors to file DSM plans for 2011 under the existing Framework.

Green Energy Act

The Green Energy Act ("GEA" or the "Act"), which received royal assent on May 14, 2009, is a landmark bill affirming Ontario's commitment to the cleaner and more efficient use of energy. The Act prioritizes renewable energy and energy conservation with regard to energy supply.

The main thrust of the Act centers on fostering the development and growth of renewable energy within Ontario. The Act attempts to remove barriers to renewable energy development (e.g., provides guaranteed connection to the grid) while also creating a favorable market environment for such technologies (e.g., feed-in tariff).

The Act also commits Ontario to promote energy efficiency and conservation. With a dual focus on renewable energy, the emphasis of the efficiency provisions falls on electricity; however, the Act does contain provisions that will affect natural gas distributors and related stakeholders. Namely, section 2 of Schedule D of the Act - proclaimed into force on September 9, 2009[14] - amended the Ontario Energy Board Act by explicitly making the promotion of energy efficiency and gas conservation an objective of the OEB. This objective must be balanced with regard for the economic circumstances of provincial energy customers, highlighting the importance of participant costs and rate increases associated with efficiency programs. Also, section 6 of Schedule D - not yet proclaimed into force - specifies that the OEB will assess electricity and gas distributors (and other parties) for expenses incurred and expenditures made by the Ministry of Energy and Infrastructure in implementing energy conservation or renewable energy programs. Gas distributors may collect the amounts assessed to them from their customers (or classes of customers) subject to regulations not yet issued.

Carbon Emission Reduction Targets

The impact of the Green Energy Act remains unclear as it relates to conservation and energy efficiency programs for natural gas distributors. It is clear that Ontario has chosen to place more

[14] On September 9, 2009 the following provisions of the *Green Energy Act, 2009* came into force:

1. Sections 1, 2 and 4 to 20 of Schedule A to the Act, which enacts the *Green Energy Act, 2009*.
2. Schedule B to the Act, which amends the *Electricity Act, 1998*.
3. Schedule C to the Act, which amends the *Ministry of Energy Act*.
4. Sections 1 to 3 and 7 to 19 of Schedule D to the Act, which amend the *Ontario Energy Board Act, 1998*.
5. Schedule I to the Act, which amends the *Co-operative Corporations Act*.

emphasis on climate change initiatives and carbon emission reductions. A recent report, "Adapting to Climate Change in Ontario," prepared by an expert panel for the Minister of the Environment lays out 59 recommendations and urges "the overall objective for the Government of Ontario is to build a climate-resilient province which will adapt well to the impacts of climate change and its challenges."[15] But until the legislation and related policy initiatives are implemented by the Government of Ontario, the effect on the Board's policy will be uncertain.

Ontario's 2007 Action Plan on Climate Change established aggressive greenhouse gas ("GHG") reduction targets for the province, using 1990 emission levels (of 175 megatonnes) as the baseline. However, these targets represent commitments established by the provincial government rather than strict legal obligations. Nevertheless, executive agencies are directed to consider these commitments as they develop policy. The following table summarizes the GHG reduction targets for Ontario.

**Table 4: GHG Reduction Targets for Ontario**

| Year | % Below 1990 level | Emissions (MT) |
|---|---|---|
| **2014** | 6% | 165 MT |
| **2020** | 15% | 149 MT |
| **2050** | 80% | 35 MT |

The Environmental Commissioner's ("ECO") December 2009 report notes that actual GHG emissions in 2007 were 197 MT, which represents a 13% increase over 1990 levels. According to the ECO report, the impact of current plan initiatives would only reduce GHG emissions to 180 MT by 2014, which is 15 MT short of the target. The report notes that 75% of this reduction depends on the phase-out of the four remaining coal fired thermal plants by 2014, which the ECO believes places too much reliance on the exact timing and magnitude of this event. According to the ECO report, natural gas accounted for 26% (or 51.2 MT) of GHG emissions in 2007 in Ontario, while coal accounted for 14% (or 27.6 MT) and refined petroleum products account for 38% (or 74.9 MT).[16]

15 "Adapting to Climate Change in Ontario," Report of the Expert Panel on Climate Change Adaptation, November 2009, at 6.

16 Environmental Commissioner of Ontario, "Annual Greenhouse Gas Progress Report 2008/2009," December 2009, at 36.

## VII. Overview of Gas DSM in Canada and the United States

This section presents an overview of several recent publications and articles relating to conservation, energy efficiency and demand side management programs in Canada and the United States. Major findings from each of the publications or articles are presented in an effort to place the current Ontario DSM proceeding in context. Inclusion of a particular report should not be considered an endorsement of any positions or recommendations contained in that report. Rather, this section is intended to inform the Board and stakeholders about the different perspectives on DSM that are evident in the current literature on the subject. Some of the information and findings from these publications will be useful later as we review the different elements of the DSM framework in Ontario.

Canadian Natural Gas Distributors' Best Practices in Demand Side Management[17]

The purpose of the report was to review the best practices of Canadian gas utilities in demand side management. The report was first published in 2005, and was updated in July 2008. According to the report, the following factors were determined to influence how a gas company implements and manages its DSM activities:

- Ownership structure: investor-owned utilities vs. crown corporations
- Size of the utility: annual throughput of gas per number of customers
- Breakdown of customers by class: percentage of residential vs. commercial/industrial
- Differences among provinces in fuel mix available and relative price of natural gas and electricity: provinces with the highest natural gas prices offer the strongest price signals for customers to use natural gas wisely.

According to the report, seven natural gas utilities in Canada offer DSM programs. The following table provides a profile of those companies.

[17] IndEco Strategic Consulting, Inc., prepared for the Canadian Gas Association, "Canadian Natural Gas Distribution Utilities' Best Practices in Demand Side Management: Study Update," July 2008.

**Table 5: General characteristics of natural gas utilities in Canada (2007)[18]**

| Utility | Owner | Throughput $10^6 m^3$ | Throughput $10^6 GJ$ | Customers | % Residential |
|---|---|---|---|---|---|
| ATCO Gas | Investor | 6,279 | 238 | 1,003,291 | 91.4% |
| Enbridge Gas | Investor | 12,073 | 447 | 1,860,857 | 91.6% |
| Gaz Metro | Investor | 6,286 | 233 | 174,583 | 66.8% |
| Manitoba Hydro | Crown | 2,156 | 75 | 261,159 | 90.6% |
| SaskEnergy | Crown | 3,564 | 132 | 335,829 | 89.0% |
| Terasen Gas | Investor | 6,954 | 258 | 916,220 | 90.1% |
| Union Gas | Investor | 13,878 | 514 | 1,300,000 | 90.2% |

The following table indicates the regulatory agency responsible for approving DSM programs, and the year when DSM programs were first approved for each gas utility.

**Table 6: Regulatory environment of natural gas utilities conducting DSM in Canada[19]**

| Utility | Regulatory Agency | DSM Since |
|---|---|---|
| ATCO Gas | Alberta Utilities Commission | 2001 |
| Enbridge Gas | Ontario Energy Board | 1995 |
| Gaz Metro | Regie de l'energie Quebec | 1999 |
| Manitoba Hydro | Manitoba Public Utilities Board | 2005 |
| SaskEnergy | Crown Investment Corporation | 2001 |
| Terasen Gas | British Columbia Utilities Commission | 1997 |
| Union Gas | Ontario Energy Board | 1997 |

The report indicates that from 2000 through 2007 more than $288.7 million was spent on DSM by natural gas utilities in Canada.[20] Annual DSM expenditures increased steadily over the first four years of this period (at an annual rate of 16.8%), and more dramatically over the latter three years (at an annual rate of 31.1%), with total expenditures in 2007 being more than four times that in 2000. According to the report, the early growth was attributed to both an increase in the number of companies participating in DSM and an increase in DSM budgets within individual companies, while growth in the latter years was due almost exclusively to significant increases in DSM budgets. The following table summarizes DSM expenditures and energy savings across Canada from 2000 through 2007.

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[18] Ibid, at 9. The term "LDC" here refers to gas distributors.

[19] Ibid, at 10.

[20] Throughout the report, all references to dollar amounts for Canadian companies are expressed in $CDN, and all references to dollar amounts for U.S. companies are expressed in $US, unless otherwise noted.

**Table 7: Canadian Nationwide DSM expenditures and energy savings (2000 – 2007)[21]**

| Year | Utilities | DSM Expenditures (millions) | Gas savings from DSM (millions of $m^3$/yr) | Cost per $m^3$ | Gas savings from DSM (millions of GJ/yr) | Cost per GJ |
|---|---|---|---|---|---|---|
| 2000 | 4 | $16.6 | 91.8 | $0.18 | 3.48 | $4.76 |
| 2001 | 6 | $22.1 | 138.2 | $0.16 | 5.24 | $4.22 |
| 2002 | 6 | $23.4 | 150.2 | $0.16 | 5.69 | $4.12 |
| 2003 | 6 | $26.0 | 153.4 | $0.17 | 5.81 | $4.47 |
| 2004 | 6 | $30.9 | 170.9 | $0.18 | 6.47 | $4.78 |
| 2005 | 7 | $41.8 | 202.0 | $0.21 | 7.50 | $5.59 |
| 2006 | 7 | $59.5 | 230.0 | $0.26 | 8.50 | $6.98 |
| 2007 | 7 | $69.8 | 217.8 | $0.32 | 8.10 | $8.65 |

American Gas Association report on Energy Efficiency[22]

The AGA surveyed its members regarding regulatory approaches to promoting energy efficiency. Key findings of that survey are as follows:

- The average American home uses one third less natural gas than it did a quarter century ago. The reduction in per-capita natural gas use has been driven primarily by energy efficiency – whether due to tighter building envelopes, increased appliance efficiency or changes in consumer behavior influenced by utility-sponsored programs.

- At the end of 2007, 57 local distribution companies in 32 states and Canada had natural gas energy efficiency and conservation programs serving 34 million residential customers. Additional programs that came online in 2008 and early 2009 raised the number of states with energy efficiency programs to 34.

- These companies spent more than $329 million in 2007 on direct program costs and reached nearly one million residential customers, for a savings of 9 percent of total natural gas usage per residential participant.

- In 2007, gas utility energy efficiency programs saved 218 million therms (or 616.4 cubic meters) and prevented nearly 1.3 million tons of $CO_2$ from being released into the atmosphere.

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21 Ibid, at 18.

22 American Gas Association, Natural Gas Rate Round-Up, "Update on Regulatory Approaches to Promoting Energy Efficiency," May 2009.

**Table 8: 2007 Savings from Gas Utility Energy Efficiency Programs**

| Customer Class | Gas Savings (million therms) | Gas Savings ($M^3$) |
|---|---|---|
| Residential | 61.6 | 174.2 |
| Commercial/Industrial | 142.5 | 402.0 |
| Low Income | 7.8 | 21.4 |
| Other | 6.1 | 16.1 |

- All 34 states with energy efficiency programs allow utilities to recover direct program costs. In addition, 19 states allow utilities to recover lost margins, and 11 states and Ontario provide utilities with the opportunity to earn a financial reward or profit on the operations of natural gas energy efficiency programs.

- Approximately half of the respondents to the AGA survey use a stand-alone energy efficiency tariff, or a special energy efficiency rider to a standard service tariff, in order to recover program costs. Another quarter of companies recover these costs in base rates, and the remaining quarter of utilities add a surcharge to customer bills to recover program costs.

- Survey respondents report that tracking costs and recovering energy efficiency expenditures through a tariff or rider tends to provide for matching of program costs with program expenses, while inclusion of costs in base rates leads to either over-recovery or under-recovery of program costs.

- 31 companies in 16 states recover lost revenues and margins through non-traditional rate designs (either revenue decoupling or a flat monthly rate design), while 11 companies in four states use a lost margin tracker.

- 21 utilities in 11 states and Ontario are earning on their investment in energy efficiency programs or have been granted authority to defer for later recovery in rates their energy efficiency related earnings. Eight utilities use a performance target incentive, four utilities use a rate of return adder, and nine utilities use a shared savings mechanism to earn a profit on energy efficiency programs.

- Shared savings incentives measure actual ratepayer benefits and allow the company to earn a percentage of savings received by customers. A major difficulty with the shared savings incentives is that savings are difficult to measure and verify, and some states have developed problems with the measurement and verification activities required to authorize incentive payments.[23]

National Regulatory Research Institute Report[24]

This report by NRRI, which is the research arm of the National Association of Regulatory Utility Commissioners ("NARUC"), describes the problems that regulators have confronted in maximizing the benefits of energy efficiency programs and offers four guiding principles to enhance or maximize those benefits. Among the problems cited by the report are poorly designed programs that: 1) have included "free riders" as participants; 2) featured non-alignment of program objectives with a specific market or "behavioral" problem; 3) provided low utility motivation for success; and 4) contained inadequate utility financial inducements for consumer participation.

The report observes that it is not enough to implement energy-efficiency initiatives that pass some cost-benefit analysis, but that those programs should produce the highest possible benefits for the dollars expended. The objective should be to maximize utility performance, either by producing the most energy savings from the dollars expended, or by minimizing the dollars spent in achieving the targeted level of energy savings. Even if a utility's energy efficiency initiatives pass the cost effectiveness test and are therefore economically tenable, they could fail to maximize economic benefits. The article concludes that energy efficiency is not always synonymous with economic efficiency.

The report discusses what results should be achieved by energy efficiency programs. Namely, the major social benefit from energy efficiency comes from the avoidance of costs by energy utilities as they provide fewer kilowatt hours or therms to their customers. These costs include variable costs, such as fuel and maintenance, as well as capital expenditures for new capacity that could be deferred. Benefits depend not only on physical energy savings but also on the dollar value of those savings. The article notes that many experts consider energy efficiency to be a low-cost, near term strategy for greenhouse gas mitigation. Specifically, energy efficiency can play a key role in meeting carbon

[23] The California Public Utilities Commission adopted a shared savings incentive mechanism in September 2007, but has opened a new rulemaking proceeding to review the mechanism because of major controversies surrounding delays in the completion of verification reports, concerns over methodologies used in the verification reports, and the wide range of claimed energy efficiency program results.

[24] National Regulatory Research Institute, "How Regulators Can Help to Increase the Benefits from Utility Energy Efficiency Initiatives," Kenneth Costello, July 2009.

dioxide targets in the near-term, as we await commercialization of carbon-constrained technologies such as nuclear power, carbon capture and storage from coal plants, and some forms of renewable energy.

The article proposes four guiding principles for regulators to consider as they seek to maximize the benefits of energy efficiency and conservation programs. These include the following:

- Align individual initiatives with an identified market or "behavioral" problem. Market problems can include inadequate consumer information or information that is confusing and difficult for utility customers to interpret; significant uncertainty about benefits; high transaction costs; and split incentives between builders and occupants.

- The benefit-cost ratios of potential utility initiatives should determine their prioritization. All initiatives with a benefit-cost ratio greater than one are economically justified. However, the relative ratio across initiatives can affect how utilities should allocate dollars among competing initiatives.

- Harmonize a utility's financial and other motivations with energy efficiency initiatives. At a minimum, the utility hopes to avoid any negative financial consequences, which could require a revenue decoupling rider, a lost revenue adjustment mechanism, or a rate design that protects the utility against unexpected sales declines (e.g., straight fixed-variable). The regulator could go further by allowing the utility to earn a profit from taking on cost effectiveness initiatives comparable to profits for supply-side alternatives. Profits can come from shared savings, performance target incentives, and a rate-of-return adder. Without financial inducements, regulators would have to more closely monitor the utility to make sure it is carrying out its goal for energy efficiency.

- Use the most effective institutional arrangement for designing, administering, and implementing the energy efficiency initiatives. The utility might not be the preferred party to undertake these functions. Outsourcing these functions to a third party could increase the benefits from energy efficiency initiatives funded by the utility and its customers. The third party could be a not-for-profit entity or a state government agency that coordinates all the utility energy efficiency activities in the state. An outside party could have more expertise, more experience, and more robust financial incentives than a utility with which to maximize the benefits from energy efficiency.

Some of the findings contained in this report will be useful later as we review and evaluate the different elements of the DSM framework in Ontario.

American Council for an Energy-Efficient Economy Reports

The ACEEE issued a report in February 2008[25] which identified a number of common traits observed in successful energy efficiency programs for both electric and gas utilities across the U.S. The report characterizes these noteworthy programs as helping to define "best practices" for today's leading energy efficiency programs. These include:

- In many categories of programs, the approaches used are proven and are providing consistent, reliable, and cost-effective savings. We are definitely seeing a certain maturity to programs and program approaches. Program managers, administrators, and implementers have really figured out what works and what doesn't after many years of experience with different approaches and program structures.
- There are also many innovative programs – programs using new approaches, promoting new technologies, and targeting customer segments that haven't been well-served or even have been entirely missed by past programs. Examples include programs targeting industrial processes, agriculture, high tech industries (such as data centers) and the food service industry.
- Personal contacts with customers by program representatives yield strong results. Utility key account representatives or their equivalent from non-utility organizations administering programs play important roles for many programs. Such representatives earn customer trust and confidence in programs and services offered by their organizations through sustained relationships.
- For many types of programs, bringing in recognized industry experts that echo the energy efficiency message while focusing on key industry objectives seems an approach that's particularly successful. This approach seems especially useful in industrial, agriculture, and commercial construction programs.
- Energy efficiency program portfolios available to all customers are comprehensive. Such portfolios of programs provide extensive coverage for all types of customers at all types of decision points, primarily equipment purchase/replacement, retrofit, and new construction (and major renovations and additions).
- Programs themselves are increasingly comprehensive, offering a full menu of services (including incentives, marketing, technical assistance, training and education) for a full menu of customer end-use applications – lighting, appliances, HVAC, building

[25] American Council for an Energy-Efficient Economy, "Compendium of Champions: Chronicling Exemplary Energy Efficiency Programs from Across the U.S.," Report Number U081, February 2008

envelope, and other systems and technologies. Many leading programs offer a single portal or program contact to access a full range of applicable program services.

- There are organizations with long-standing, well-established programs that continue to be very successful as well as many new organizations that have just initiated – or re-established – programs and have done well with rapid start-ups.
- Collaborations among stakeholders and market participants are key elements of numerous successful programs. Energy efficiency programs increasingly involve a broad spectrum of allies, including architects, consulting engineers, designers, contractors, manufacturers, suppliers, retailers, government agencies, local governments, and other decision-making bodies.
- Collaboration among program administrators and providers is a successful approach, a way to leverage resources and reach broader areas with common and consistent program services and messages.
- There is an increasing emphasis on statewide approaches and programs, even if not delivered by the same entity to all customers. For example, the utilities in the states of California, Connecticut, Iowa, and Massachusetts offer many programs based on a common program platform of services.
- Different program models and approaches are in place: market transformation (facilitating fundamental changes in markets that lend to greater shares of energy-efficient products and services) and resource acquisition (seeking to achieve direct, measurable savings customer-by-customer). Many programs really meld these approaches and seek both outcomes – fundamental changes in markets and direct, measurable energy savings.
- There are many different types of organizations that administer and implement exemplary programs, both utilities and non-utilities (government agencies, non-profit organizations, contractors, etc.)
- The U.S. EPA/DOE ENERGY STAR program is prominent within applicable programs, especially consumer products and new homes, and is increasing in commercial areas. The ENERGY STAR brand is common among a growing roster of different types of programs – moving beyond products and into services, such as home and business retrofits.
- There are many exemplary new construction programs, both residential and commercial/industrial. This emphasis reflects overall program portfolio goals of avoiding "lost opportunities" (building new, inefficient buildings).
- There are programs continuing to innovate to try to achieve deeper savings with program participants, such as boosting incentives and services for customers who choose to implement large sets of recommendations, rather than single measures or small sets of measures. Comprehensive approaches are being taken in all customer segments – programs seek to improve the energy efficiency of entire buildings or industrial processes.

In October 2008, the ACEEE issued a report that contained a scorecard which ranked the 50 U.S. states according to their energy efficiency policies. Scores were based on eight factors: 1) utility and public benefit programs and policies (including spending on energy efficiency programs for electricity and natural gas, annual savings from energy efficiency programs for electricity only, targets or resource standards, and utility incentives or removal of disincentives); 2) transportation policies; 3) building energy codes (including level of stringency and enforcement/compliance); 4) combined heat and power; 5) appliance and equipment efficiency standards; 6) lead by example initiatives (such as state buildings and fleets); 7) research, development and deployment; and 8) financial and information incentives. The table below presents the scores and ranks for the twelve states covered by our research.

**Table 9: ACEEE Ranking of U.S. State DSM Programs**[26]

| Rank | U.S. State | DSM Score |
|---|---|---|
| **1** | California | 40.5 |
| **2** | Oregon | 37.0 |
| **3** | Connecticut | 36.0 |
| **5** | New York | 32.5 |
| **6** | Washington | 32.0 |
| **7** | Massachusetts | 26.5 |
| **7** | Minnesota | 26.5 |
| **9** | Wisconsin | 26.0 |
| **10** | New Jersey | 25.5 |
| **14** | Iowa | 19.0 |
| **19** | Maine | 16.0 |
| **24** | Colorado | 15.5 |

*Note:* Highest possible score is 50 points.

The ACEEE's October 2008 report concluded that:

> Energy efficiency is the only resource that can help states actually reduce energy consumption to combat rising energy demand and create a hedge against skyrocketing energy prices – making efficiency the "first fuel" states can use to balance their energy portfolios. And by shrinking the overall reliance on energy supply, efficiency allows new clean energy resources – such as wind and solar technologies – to make up a growing slice of state energy portfolios.[27]

[26] American Council for an Energy-Efficient Economy, The 2008 State Energy Efficiency Scorecard, October 2008, ACEEE Report Number E086, at iv and v.

[27] Ibid, at vii.

TRC Test and Climate Change/Carbon Reduction Goals[28]

The authors of this paper (which was presented to the ACEEE) argue that current cost-benefit analysis conflicts with the public policy goal of using energy efficiency programs to achieve climate change objectives and to reduce carbon emissions. Specifically, they contend that policy makers continue to review energy efficiency programs under the TRC test, which fails to capture non-energy related benefits to society such as carbon reduction and national security. Consequently, the current approach in most states requires energy efficiency to be cheaper than carbon-based resources before they can be approved, thus moving energy efficiency to a minor position in the supply mix.

The article cites two other reports (known as the Stern report and the Plan B report) which state that it is necessary to rely on energy efficiency to capture between 40% and 80% of the carbon reduction needed over the next 40 years. To achieve this goal, every building in the U.S. must consume approximately 60% to 75% less energy. That article indicates this goal is achievable using current technology, with minor adjustments to current energy technologies and marketing approaches. However, the current approach for calculating benefits and costs of measures, programs, and portfolios will block this achievement. The authors argue that, under current policies, between 60% and 80% of the available building-associated savings are left untouched after the energy efficiency programs have completed their work. The remaining potential does not fit within the current benefit cost calculation approach regardless of the program's energy or climate change benefits.[29]

The authors present four concepts for consideration by regulators and policy makers. Following is a brief summary of how changes to four critical assumptions might influence the energy efficiency programs that are approved.

- Avoided Costs: In general, almost all avoided cost approaches continue to focus primarily on carbon-based supplies, such as fossil fuel generated electricity or natural gas supplies. The article states that policy makers appear to be setting climate change objectives, and then selecting an avoided cost approach that cannot achieve that objective. It asks whether renewable energy supplies should form the basis for

[28] "Reaching our Energy Efficiency Potential and Greenhouse Gas Objectives – Are Changes to Our Policies and Cost Effectiveness Tests Needed?", Nick Hall, et al, Prepared for presentation at the 19th AESP National Energy Services Conference and Expo, January 2009.

[29] Ibid, at 3.

avoided cost calculations, and cites the example of comparing the avoided cost associated with the installation of compact fluorescent lights under a carbon-based cost of $0.06 per kilowatt hour versus a renewable based cost of $0.18 per kWh. It concludes that if utilities have to install more capacity to meet needs, energy efficiency may be more cost effective than renewable energy; however, it is not selected because of the benefit-cost approach for energy efficiency.

- Discount Rate: The article questions whether the discount rate in the TRC test understates the future value of benefits attributed to energy savings, especially if energy efficiency and conservation are intended to reduce carbon emissions and slow climate change. It suggests the possibility that the discount rate for climate change purposes should be negative, resulting in a higher value allocated to future energy savings. In other words, the decision to approve energy efficiency programs should be more than just an assessment of alternative financial outcomes, but a recognition that the financial importance of energy savings and carbon reduction increases over time. The current discount rate commonly used in the TRC test minimizes the benefits of energy efficiency measures beyond the 25th year, even though the benefits of installing new windows or building insulation continue well beyond that timeframe.

- Value of Carbon Saved: The authors argue that regardless of the approach used to set a value for carbon reduction, if climate change objectives are to be met with energy efficiency programs, the benefit cost calculation will need to include a scientifically accurate and politically acceptable value for the carbon not released. They note that several states have begun to include or consider including carbon values in their benefit cost tests, but that no state is setting carbon values at the projected value of the benefit over the predictable future (partly because these are highly uncertain). Failure to include a value for carbon reductions from the benefit cost test reflects poor public policy, according to the authors.

- Effective Useful Life: The article notes a tendency among policy makers to utilize conservative estimates of the effective useful life of energy efficiency measures, and observes that most discount rates tend to make savings past year 25 essentially worthless regardless of the amount of energy that is actually saved. It concludes that vast amounts of energy savings in the United States become essentially worthless under standard benefit cost tests when savings occurring beyond the policy-based effective useful life period are not valued as a future energy resource. The authors contend that the majority of the value from savings on energy efficiency measures such as replacement windows, attic insulation, and new building envelopes is not recognized in benefit cost calculations because policy makers have underestimated the value of the long-term savings provided by those measures.

## VIII. ISSUE #1: DSM COST EFFECTIVENESS TEST

### a. Existing DSM Framework in Ontario

In its August 2006 decision in EB-2006-0021, the OEB determined that the TRC test was the appropriate economic test to measure cost effectiveness, and directed natural gas distributors to use the TRC test when evaluating the cost effectiveness of a DSM measure or program to determine whether it can be considered for inclusion in the DSM portfolio. The Board also indicated that the considerations and tests identified in EBO 169-III that could be used to determine which DSM measures and programs are actually selected for a portfolio should continue to apply.

As established in EBO 169-III, some of the factors to be considered in the selection of potential programs are: 1) achievable potential; 2) capture of potential lost opportunities; 3) synergies among programs; and 4) the breadth of the portfolio. The Board also set out the screening process that it expected distributors to use. As the first screen, the Board endorsed the use of the Societal Cost Test, and indicated that this test was an effective way of addressing environmental externalities. The second screen involved using the Rate Impact Measure test, as the Board was of the view that programs which pass this test will have net societal benefit, without requiring cross-subsidization or causing any net rate impact. The third screen was a consideration of undue burden and second round-impacts. That is, any increase in rates resulting from programs that passed the Societal Cost Test but failed the Rate Impact Measure test, not impose an undue burden on an individual or class of customers. Rate increases need to be considered both in the short and long term and assessed to ensure that they do not cause second round net societal costs that are expected to exceed the first round net societal benefits. The fourth screen involved a qualitative assessment of those programs that failed the third screen, as well as an overall evaluation of programs that passed the third screen. This assessment involved consideration of additional factors such as the magnitude and importance of avoided lost opportunities, the size of the net benefits associated with the implementation of the program, the improvement of safety and system reliability, and the contribution of the program to the breadth of the portfolio. Each program should be assessed from a pragmatic point of view regarding the likelihood of its acceptance and success, since even the most economically attractive DSM program can be useless unless customer acceptance is forthcoming. The fourth screen also involves the assessment of each program which passed Screens 2, 3, or 4, to determine the program's suitability as a candidate for further consideration in comparison to the other surviving programs.

In the Draft DSM Guidelines, OEB staff clarified the components of the TRC test, which measures the benefits and costs of DSM efforts from a societal perspective (although some would argue that a societal view would include externalities). 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 a customer. 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 include any equipment costs and program support costs associated with delivering that equipment to the marketplace. In addition, the TRC test includes the reduction in use of other resources such as electricity, water or other resources.

<u>DSM equipment costs represent the costs to purchase and install the more efficient equipment, and are typically paid by the participant/customer and the distributor.</u> They include capital, installation, and operating and maintenance costs associated with the technologies of the DSM program. The TRC test does not differentiate between who (distributor or customer) pays the costs of the equipment. According to the Board's existing DSM Framework, equipment costs, whether paid by the customer or distributor, should be defined relative to a base case. In other words, the relevant cost for purposes of the TRC test is the difference between the installed cost associated with the energy efficient equipment and the cost of the equipment that would have been purchased in the absence of the DSM program.

<u>DSM program costs are those incurred by the distributor, and include costs associated with marketing, delivering and supporting the DSM activity.</u> Participant or customer incentive costs, such as rebates, are considered transfers under the TRC test and are not included in the analysis. There are five major categories of distributor costs: 1) development and start-up costs; 2) promotional costs (i.e., marketing and advertising); 3) equipment and installation costs (e.g. specialized software or tools); 4) monitoring and evaluation costs; and 5) administrative costs.

According to the Board's existing DSM Framework, the cost effectiveness of DSM shall be evaluated in stages at many different levels, including technology or measure, program and portfolio.

The TRC test is performed at each level. The results of the TRC test are expressed as a net present value (NPV). The TRC test sums the stream of expected future benefits and costs over the life of the equipment/technology and uses a discount rate to express those streams as a single "current year" value. If the NPV is positive, or the benefit to cost ratio exceeds 1.0, then the DSM measure, program or portfolio is considered cost effective from a societal perspective. The Board has determined that the appropriate discount rate is the utility's incremental after-tax cost of capital, based on its latest prospective capital structure, debt and preferred share cost rates, and approved return on common equity.

In its March 2009 report in the Consultation on Energy Issues Relating to Low-Income Consumers (EB-2008-0150), the Board indicated that programs targeted to low-income consumers may not be consistent with the general principle that DSM programs deliver TRC results greater than 1.0, and that failure to meet the cost-benefit test should not necessarily result in disqualification for the overall DSM portfolio.

The Ontario Power Authority[30] has adopted the Program Administrator Cost Test as well as the TRC test for the evaluation of its electricity conservation programs. The PAC Test measures the net costs of a DSM program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC benefits, while costs are defined more narrowly (i.e., participant costs are excluded).

b. Stakeholder Comments

Stakeholder perspectives vary considerably regarding the value and validity of the TRC test for assessing DSM programs. Some stakeholders have questioned the input assumptions (including the appropriate discount rate) used in the calculation of the TRC test to screen DSM technologies and programs. They have suggested broader tests or alternative methods for screening low-income programs in order to measure such non-energy benefits as reduced late payment and arrears management costs. It has also been noted that other jurisdictions include environmental and certain social externalities in assessing the net benefits of DSM programs. One stakeholder recommended

[30] The Ontario Power Authority is the agency responsible for planning and procuring electricity supply and facilitating conservation in Ontario.

that the Board consider the use of a "Scorecard" approach or an alternative test (e.g., the Low Income Public Purpose Test) for programs designed to address low-income customer needs. The scorecard approach would evaluate programs based on a variety of metrics including gas savings, customer satisfaction, levelized cost of the intervention, etc.

Both gas utilities endorse continued use of the TRC calculations, but are concerned that a strict approach will favor programs with the highest net TRC savings at the expense of other worthy programs with deep conservation measures, such as thermal envelope improvements that have long-term benefits but lower net TRC savings. Utilities have argued that specific DSM programs with a TRC below 1.0 should be approved as long as the overall portfolio is determined to be cost effective. This policy would allow natural gas utilities to pursue innovative DSM technologies and to implement DSM programs that serve the low-income market or that may be considered more aggressive or less proven in the market.

Representatives of environmental interests support the concept of a TRC test with reservations regarding associated DSM targets, but preferred that savings be more firmly tied to actual program results rather than forecasts and assumptions. They also support a negotiated approach that would drive payouts only for excellence in achieving targets and development of new targets based on achieved or verified results, conservation potential and amount of DSM budget.

c. Approach in Other Jurisdictions

Types of Cost Effectiveness Test Used

There are a variety of different cost effectiveness tests which can be used to evaluate and measure energy efficiency and conservation programs. Generically, a cost effectiveness test measures the net present value of benefits against the net present value of costs at a specified discount rate.

1) **The Total Resource Cost** test measures the net costs of a demand side management program as a resource option based on the total costs of the program including both the participants' and the utility's costs. This test represents the combination of the effects of a program on both the customers participating and those not participating in a program.[31]

[31] State of California, Governor's Office of Planning and Research, "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects," July 2002, at 18.

| Benefits | Costs |
|---|---|
| ➢ Savings from avoided supply costs using net program savings (i.e., savings net of changes in energy use that would have happened in the absence of the program)<br>➢ Avoided supply costs for the energy using equipment not chosen by the program participant | ➢ Program costs incurred by <u>both</u> the utility and the participant<br>  ➢ Equipment<br>  ➢ Operation and maintenance<br>  ➢ Installation<br>  ➢ Program administration<br>  ➢ Removal of equipment (less salvage)<br>➢ Increase in supply costs for periods in which load is increased<br>➢ Tax credits are considered reduction in costs<br>➢ Increased supply costs for utility providing fuel that is chosen as result of the program |

2) **The Societal Cost Test** is a variant on the TRC test. The Societal Cost Test differs from the TRC test in that it includes the effects of externalities (e.g., environmental, GHG emissions, national security, etc.), excludes tax credit benefits, and uses a different (societal) discount rate. [32]

| Benefits | Costs |
|---|---|
| ➢ Savings from avoided supply costs using net program savings (i.e., savings net of changes in energy use that would have happened in the absence of the program)<br>➢ Avoided supply costs for the energy using equipment not chosen by the program participant<br>➢ Environmental and social externalities | ➢ Program costs incurred by <u>both</u> the utility and the participant<br>  ➢ Equipment<br>  ➢ Operation and maintenance<br>  ➢ Installation<br>  ➢ Program administration<br>  ➢ Removal of equipment (less salvage)<br>➢ Increase in supply costs for periods in which load is increased<br>➢ Increased supply costs for utility providing fuel that is chosen as result of the program |

3) **The Participant Test** is a measure of the quantifiable benefits and costs to the customer as a result of participation in a program. This relationship is commonly expressed as the payback period, or the number of years it will take for the benefits to equal the initial investment. Since many customers do not base their decision to

32 Ibid.

participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer. [33]

| Benefits | Costs |
|---|---|
| ➢ Reduction in customer's utility bill<br>➢ Customer incentive or rebate<br>➢ Tax credits | ➢ Cost of equipment and installation<br>➢ Cost of removal (less salvage value)<br>➢ Ongoing operation and maintenance |

4) **The Ratepayer Impact Measure** ("RIM") test measures what happens to customer bills or rates due to changes in utility revenue and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.[34]

| Benefits | Costs |
|---|---|
| ➢ Savings from avoided supply costs | ➢ Program overhead costs<br>➢ Utility/Administrator incentive costs<br>➢ Utility/Administrator installation costs<br>➢ Incentives paid to participant<br>➢ Lost revenues due to reduced energy bills |

5) **The Utility/Program Administrator Cost** (PAC) Test measures the net costs of a demand-side management program as a resource option based on the cost incurred by the utility or program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC benefits, while the costs are defined more narrowly. In this test, revenue shifts are viewed as a transfer payment between participants and all ratepayers. Though a shift in revenues affects rates, it does not affect revenue requirements, which are defined as the difference between net marginal energy and capacity costs avoided and program costs.[35]

33 Ibid, at 8.
34 Ibid, at 13.
35 Ibid, at 23

| Benefits | Costs |
|---|---|
| ➢ Savings from avoided supply costs of energy and demand<br>➢ Avoided supply costs should be calculated using net program savings (i.e. savings net of changes in energy use that would have happened in the absence of the program)<br>➢ Avoided supply costs for energy using equipment not chosen by the program participant only in the case of a combination utility where the utility provides both fuels | ➢ Program costs incurred by the administrator<br>  ➢ Equipment<br>  ➢ Operation and maintenance<br>  ➢ Installation<br>  ➢ Program administration<br>  ➢ Removal of equipment (less salvage)<br>➢ Incentives paid to customer<br>➢ Increased supply costs for periods in which load is increased<br>➢ Increased supply costs for energy using equipment chosen by program participant only in the case of a combination utility |

Concentric reviewed the regulatory approach to DSM in 20 jurisdictions, including five Canadian provinces, twelve U.S. states, and three countries outside North America. We found that 16 of those 20 jurisdictions had adopted formal DSM frameworks for gas distributors. Ten of those 16 jurisdictions with formal DSM frameworks have adopted the TRC test as the economic measure to determine whether DSM programs are cost effective. However, several jurisdictions use more than one cost effectiveness test, and many jurisdictions are considering a number of different variations or adaptations of the traditional TRC test as more emphasis is placed on using energy efficiency programs as an interim solution to address pressing concerns about climate change and carbon emissions until new nuclear facilities are constructed or more renewable energy resources become available. Specifically, several jurisdictions (including British Columbia) have placed an economic value on carbon emissions, which means that energy efficiency programs are more easily justified under a cost-benefit analysis. The following table summarizes the cost effectiveness tests used in the various provinces and states that were included in Concentric's research.

**Table 10: Cost Effectiveness Tests Used in Different Jurisdictions**

| Jurisdiction | TRC | Societal | Participant | Ratepayer | Utility | Program Admin |
|---|---|---|---|---|---|---|
| United States | | | | | | |
| California | **X** | | | | | X |
| Colorado | X | | | | | |
| Connecticut | X | | | | X | |
| Iowa | | **X** | X | X | X | |
| Maine | | X | | | | |
| Massachusetts | X | | | | | |
| Minnesota | | **X** | X | X | X | |
| New Jersey | X | X | X | X | | X |
| New York | X | | | | | |
| Oregon | | X | | | X | |
| Washington* | | | | | | |
| Wisconsin | X | | | | | |
| Canada | | | | | | |
| Alberta* | | | | | | |
| British Columbia | X | | | X | | |
| Manitoba | X | X | | | | |
| Nova Scotia* | | | | | | |
| Quebec | X | | | | | |
| Countries outside North America | | | | | | |
| Great Britain | X* | | | | | |
| New Zealand* | | | | | | |
| Australia* | | | | | | |

* Has not adopted formal DSM requirements for gas distributors. See explanation below for Great Britain.

Note: Bold highlights indicate this is the primary cost effectiveness test used in that jurisdiction.

In Great Britain, two Orders require gas suppliers to promote energy efficiency programs: 1) the Carbon Emissions Reduction Target 2008-2011 ("CERT"), and 2) the Community Energy Saving Program 2009-2012 ("CESP"). The Office of Gas and Electricity Markets ("Ofgem") determines a set of DSM program offerings from which the utilities may choose by applying an Impact Assessment Analysis. For each DSM measure (e.g., home attic insulation, energy efficient light bulbs, replacing water heaters, etc.), Ofgem promulgates a pre-defined carbon score. However, Ofgem leaves the ultimate decision concerning which specific DSM programs will be most cost effective to the utilities. Ofgem has determined that different programs will have different costs in various regions, and that the utilities are best able to discern those differences. This regulatory philosophy is driven by the fact that utilities in Great Britain operate in a competitive market, where customers are free to choose the lowest cost supplier that serves a particular region.

Therefore, strict cost effectiveness tests are not required by the regulator because it is presumed that utilities have a natural incentive to provide the most cost-effective programs that will achieve obligations under the CERT and CESP orders. Cost effectiveness is just one measure examined by the British regulator in its assessment of DSM programs. Programs are evaluated using Cost Effectiveness Analysis ("CEA"), which is a ratio of net benefits to unit effectiveness (in the case of Great Britain, this is the benefit or cost per ton of carbon displaced). CEA was chosen because it favors least-cost methods of achieving savings, and does not rely on particular valuations of external costs (e.g., carbon). In this way, it is similar to the TRC test. However, CEA appraisal is only one aspect of the decision making process in Great Britain. When deciding which DSM measures to pursue, regulators also consider other factors, such as international requirements, political expediency, and the ability of a given measure to address market failures and stimulate domestic innovation.

Cost-Benefit Analysis Threshold

Most jurisdictions approve energy efficiency and conservation programs that demonstrate a cost-benefit ratio ("CBR") greater than 1.0. In some jurisdictions this analysis pertains to the individual DSM program or measure, while in other jurisdictions the CBR for the entire portfolio of DSM programs is the determining factor. New York has determined that gas utilities should calculate the CBR for each proposed DSM program, but the New York PSC has the authority to approve or deny any program regardless of the cost-benefit ratio. British Columbia accepts the portfolio level approach based on achieving a portfolio TRC greater than 1.0 provided that programs, initiatives or measures with an individual cost-benefit ratio less than 1.0 are proactively designed and sufficiently support social or environmental objectives.

In Washington, the individual utilities are responsible for determining cost effectiveness. Cascade Natural Gas, in consultation with a stakeholder advisory group, has adopted a cost-effectiveness study by Stellar Processing that evaluates the cost of individual DSM measures and packages and produces levelized cost results that enable comparison between widely different program options and conservation strategies. The Cascade advisory group set a threshold for $0.85/therm for cost effectiveness.

Inclusion of Environmental and/or Social Externalities

Many jurisdictions include environmental and social externalities in the cost-benefit analysis for a specific DSM program. For example, Iowa and Colorado have modified the TRC test so that the benefits are multiplied by a factor (1.075 in Iowa and 1.05 in Colorado) to account for the avoided costs and societal benefits (e.g., reduced carbon emissions) associated with conservation and energy efficiency. Although Iowa retained a consultant to devise an appropriate adder, both Colorado and Iowa ultimately settled on their respective percentages through the judgment of the Commission.[36] Similarly, in Oregon, the Energy Trust of Oregon ("ETO"), which administers DSM programs in that state, applies a 10% credit for energy efficiency in order to recognize the benefits of conservation in addressing risk and uncertainty.

The British Columbia Utilities Commission recognizes that societal factors have significance in assessing the benefits of DSM programs, but notes that many of these factors are subjective and difficult to measure. In Massachusetts, under the Green Communities Act, the costs of complying with reasonably foreseeable environmental laws and regulations are included in the TRC test, but environmental externalities (i.e., those costs associated with environmental damages that are not, and are not expected to be, included in electricity or gas prices) are not to be included in the TRC test.

Discount Rate Applied in Cost Effectiveness Test

We found evidence in our survey of a variety of different methods for selecting discount rates across jurisdictions. Some jurisdictions rely on the utility's weighted average cost of capital (which is typically between 8% and 9%), while some jurisdictions rely on the average interest rate on U.S. Treasury securities (which is currently in the range of 3.5% to 4.5%), while still other jurisdictions apply what they describe as a "societal discount rate" (which is currently around 5%) that is intended to account for social benefits and externalities associated with DSM programs. The following table

[36] Iowa consultant recommended 10.0%, but the Commission reduced this to 7.5% for natural gas because it "seemed high", per conversation with Gordon Dunn. Decision issued in the late 1980s; no documentation could be found.

provides more information about how discount rates are determined from our research sample of U.S. states.

**Table 11: Discount Rates Used in Benefit/Cost Analysis for DSM**

| Jurisdiction | Method for Calculating Discount Rate |
|---|---|
| **California** | Utility's weighted average cost of capital (after taxes) |
| **Colorado** | Utility's weighted average cost of capital (after taxes) |
| **Connecticut** | Rolling five year average of prime rate reported by Federal Reserve adjusted for inflation using the Consumer Price Index over that same period |
| **Iowa** | 12 month average of 10-year Treasury note and 30-year Treasury bond |
| **Maine** | Utility's weighted average cost of capital (after taxes) |
| **Massachusetts** | 12 month average of 10-year Treasury notes |
| **Minnesota** | Societal discount rate based on 20 year Treasury for Societal Test and Participant Test; utility's weighted average cost of capital for Ratepayer Test and Utility Test |
| **Oregon** | Societal discount rate of 5.2% (basis unknown) |
| **Wisconsin** | Discount rate of 5.0% as input for levelized costs (basis unknown) |

<u>Different Cost Benefit Expectations for DSM Programs Serving Low Income Customers</u>

Several provinces and states in our research sample recognize the unique challenges of designing cost effective DSM programs for low income customers. In British Columbia, utilities must provide a portfolio of DSM programs with a TRC value greater than 1.0. Programs within the portfolio designed to address low-income customers may have TRC values as low as 0.8, meaning that conventional conservation programs must measure somewhat higher to raise the portfolio average above 1.0. In California, investor-owned utilities are required to provide additional reporting to show the cost savings, energy savings, and related metrics for DSM measures for low income customers with cost effectiveness scores as low as 0.25, such as certain heating and cooling measures. California's utilities measure the cost effectiveness of low-income programs using modified versions of the Participant Test and Utility Test in order to capture certain costs and benefits not typically evaluated in traditional cost effectiveness tests (such as comfort and health effects on low-income customers).[37] While emphasizing that the goal of the Low Income Energy Efficiency program is to deliver significant cost-effective energy savings, the California PUC has

[37] Report on the Proposed Short-Term (2010) Framework for Natural Gas Low-Income DSM, Final Report of the Conservation Working Group to the Ontario Energy Board (Appendix D). Prepared by IndEco Strategic Consulting Inc., August 13, 2009.

approved low-income programs for California utilities with TRC scores that range from 0.34 to 0.54 through 2011. Modified Participant Test scores for these programs range from 0.71 to 2.08.

Iowa and Colorado regulations provide that low-income DSM programs may have a benefit-cost ratio less than 1.0. Conversely, Washington, which does not have a formal requirement for DSM programs for natural gas utilities, has indicated that low-income weatherization programs must demonstrate a Savings-to-Investment Ratio above 1.0 in order to be considered cost effective. Maine has adopted an "Unquantifiable Cost Effectiveness Test" for certain programs that benefit Maine consumers, but whose benefits cannot be reliably estimated, such as target requirements for low income residential customers.

d. Recommendations

With the passage of the Green Energy Act, the provincial government has signaled its intent to address climate change by reducing carbon emissions and increasing dependence on renewable energy resources rather than fossil fuels. As noted earlier, Ontario has established aggressive goals for reducing greenhouse gas emissions by 6% by 2014 (compared to 1990 levels) and by 15% by 2020 (compared to 1990 levels). Consistent with the above goals is the government's commitment to phase out coal-fired generation by 2014. Further, the OEB has indicated its desire to address issues affecting low-income energy consumers. These various policy objectives place increasing importance on energy efficiency and conservation programs.

From Concentric's perspective, the traditional TRC test is no longer the best cost effectiveness test for evaluating DSM programs in Ontario because it does not consider environmental and/or social externalities. In order to evaluate DSM programs that help the Board achieve more stringent conservation and climate change objectives, Concentric recommends that the Board consider adopting the Societal Cost Test (which includes all reasonably estimable externalities including CO2 emissions) as its primary method of assessing the cost effectiveness of proposed DSM programs. Under this approach, the Board would approve all energy efficiency and conservation programs with a benefit/cost ratio greater than 1.0 (subject to the budget constraints discussed under Issue #6 below). Further, Concentric recommends that the Board consider using the Program Administrator Cost test to prioritize the proposed DSM programs and measures. Priority would be given to those programs and measures with the highest PAC test results, thereby aligning DSM targets with DSM spending.

In our opinion, the Societal Cost Test has several advantages over the traditional TRC test, given the provincial policy objectives regarding energy conservation and climate change. First, the Societal Cost Test provides gas distributors with a stronger incentive to design and deliver energy efficiency programs that achieve both short-term and long-term energy savings. Second, by including environmental (e.g., carbon emissions reduction) and social externalities (e.g., improved comfort, reduction of bad debt from low income consumers as a result of DSM programs), the Societal Cost Test gives the utility more incentive to develop DSM programs and measures that result in meaningful reductions in gas consumption. Adoption of the Societal Cost Test would most likely increase the number of DSM measures and technologies that are determined to be cost effective. However, it would not impact customer rates, because those rates are dependent on the approved budgets for the DSM programs, which are discussed under Issue #6 below.

Concentric recommends that the Board separately evaluate the cost effectiveness of proposed DSM programs for low-income customers. We find merit in the approach used in California, which has established a stand-alone framework for DSM programs designed to serve low-income customers. One benefit of this approach is that it allows utilities to design and deliver targeted DSM programs to this unique customer group even though the programs may not pass the traditional cost-benefit analysis. The Board has indicated that DSM programs for low-income customers should not be required to achieve a TRC result of greater than 1.0. Although Concentric believes that it is important for the Board to continue to evaluate the cost effectiveness of low-income programs, we agree that it would be appropriate to relax the standard for these programs. Low-income consumers represent a significant proportion of potential conservation benefits, both in terms of quantifiable reductions in natural gas consumption, and in social benefits (such as increased health and comfort) that are extremely difficult to quantify. Concentric recommends that the Board consider adopting a Societal Cost test threshold for low-income programs of 0.60 to 0.75. This range is somewhat more aggressive than the 0.80 TRC result used in British Columbia, but more conservative than the 0.25 modified Participant Test result adopted in California. The recommended range of 0.60 to 0.75 is higher because it utilizes the Societal Cost test (which includes externalities), while the range in other jurisdictions relates to the TRC test or the Participant test (which do not include externalities). We believe this range strikes an appropriate balance between the policy objective of encouraging energy efficiency programs for low-income consumers and ratepayer advocate concerns regarding the impact of DSM program costs associated with such programs on customer rates. The Board may wish to modify this range after one or two program cycles, when it has more information available regarding the success of low-income programs and their impact on customer rates.

Finally, Concentric recommends that the Board apply the cost effectiveness test on a program basis rather than a portfolio basis. We believe that each individual DSM program or measure should be evaluated on its own merits, and that the Board should favor those programs and measures which are most cost effective. A portfolio approach is not recommended because we believe that it tends to blur the distinction between more effective programs and less effective programs, and it limits the flexibility of the Board to approve specific DSM programs as new technologies emerge and as policy objectives change. Although the utilities have expressed concern that applying the cost effectiveness test on a program basis discourages them from pursuing more innovative technologies, Concentric believes that concern can be addressed through approval of special funding for research and development efforts (similar to what is done in Minnesota) and for pilot programs that may not have benefit/cost ratios greater than 1.0, as long as the Board has an opportunity to review the success of those programs within two or three years.

## IX. Issue #2: DSM Avoided Costs

### a. Existing DSM Framework in Ontario

Under the TRC test, the benefits of DSM programs are defined as "avoided costs", which represent the benefit to society of not having to provide an extra unit of natural gas supply to the customer. As established in the August 2006 decision in EB-2006-0021, each gas distributor must calculate avoided costs for natural gas, electricity and water that reflect its cost structure and service territory. In order to ensure consistency, a common methodology is used to determine the costs. The distributors are required to coordinate the timing for selecting commodity costs so that they are comparable. Distributors submit their avoided costs for review as part of the multi-year plan filing. Approved avoided costs are in place for the duration of the plan, but the commodity portion of the avoided costs is updated annually. Since avoided costs are long term projections, the Board agreed that updating the costs, other than the commodity costs, on a three year cycle should not cause benefits to be significantly under or overstated.

Avoided costs include the costs of obtaining, transporting, and storing the gas commodity. Associated electricity and water costs are incorporated as well. Gas commodity costs are assessed using standard forecasts, relating prices to the NYMEX price at Henry Hub and other points, and applying seasonal adjustment and load shape factors. Transportation costs are based on approved pipeline tolls for different zones in the province. Gas storage rates used in avoided costs assessments are derived from contracted market-based rates. The avoided electricity costs are based on wholesale prices as reported annually by the Independent Electricity System Operator. Water costs are based on wholesale water prices in a variety of regions within Ontario. The wholesale price of water includes the cost of sewage and water treatment, but not the cost of distribution or sewage collection.

In the Draft DSM Guidelines, OEB staff provided clarification of the use of avoided costs. For natural gas distributors, supply costs include the gas commodity and the avoided distribution system costs such as mains, compressor stations and storage facilities. 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 the primary target of the program, the TRC test will accommodate an assessment of savings associated with avoiding the use of these resources as well. The Draft DSM Guidelines propose that distributors wishing to assess resource savings relating to other energy forms or water would need to use avoided cost estimates for those resources in the same manner that natural gas avoided costs are used.

The benefits in the TRC test are driven primarily by the annual natural gas savings. They are often calculated at the technology level and are commonly referred to as prescriptive savings estimates. Savings and technology costs are generally defined relative to a frame of reference or base case. To accurately specify the impacts of any given technology, the important question is – "What would have happened in the absence of the technology?" At a minimum, the base case technology should be equal to or more efficient than the technology benchmarks mandated in energy efficiency standards.

b. Stakeholder Comments

Certain stakeholders have questioned the assumptions underpinning the natural gas price forecasts used by the utilities to estimate avoided costs, the frequency with which avoided costs are updated, and the methodology used to calculate savings from the replacement of inefficient appliances. Some stakeholders have also questioned whether it is appropriate for the OEB to use the same commodity price forecast for both gas utilities.

One utility expressed concern that it may be unnecessarily burdensome to require that natural gas avoided costs be calculated for each customer class in discreet steps. Further, this same utility contends that when updates are made to avoided costs, or any other input assumptions used to calculate incentives, the same updates should also be applied to the DSM target. Several ratepayer advocates shared this concern regarding the use of different avoided costs for the calculation of DSM targets and different methods for calculating the TRC savings based on which level of incentives is determined.

c. Approach in Other Jurisdictions

<u>Avoided Cost Calculation</u>

Avoided cost calculations typically contain assumptions regarding gas commodity costs, costs related to operating and maintenance of the gas distribution system, capital costs for distribution infrastructure, costs associated with system reliability, and costs for environmental and social externalities (such as avoided emissions). Minnesota and California employ sophisticated econometric models to calculate avoided costs for gas conservation. The California PUC has outsourced this work to a contractor, while utilities in Minnesota quantify avoided costs using a software tool called BENCOST, which requires an extensive set of general-purpose and project-specific input assumptions, each of which is assigned an escalation factor.[38]

Placing a Value on Carbon Emissions

Several jurisdictions in our research sample have assigned a value to carbon emissions, or have placed a tax on natural gas to account for its environmental impact. The following table summarizes available information for the jurisdictions covered by our research survey.

**Table 12: Value Assigned to Carbon Emissions**

| Jurisdiction | Value Placed on Carbon Emissions |
|---|---|
| **British Columbia** | Established a carbon tax of $15 CDN per ton effective July 1, 2009, and increasing by $5 CDN per ton for each of the three succeeding years. This was projected to result in a tax on natural gas of $0.7894/MMBtu in 2009 increasing to $1.5788/MMBtu by 2012. The carbon tax is revenue neutral, meaning that revenues are to be returned to taxpayers through reductions in other provincial taxes. |
| **Great Britain** | Recently increased the value from $17 US per ton to $35 US per ton for traded carbon emissions and from $44 US per ton to $84 US per ton for non-traded carbon emissions. For energy efficiency programs, Great Britain considers electricity to be associated with traded carbon emissions, and natural gas to be associated with non-traded carbon emissions. |
| **Oregon** | Energy Trust of Oregon applies a credit of $15 US per ton for carbon dioxide and will update that figure as information improves. |
| **New Jersey** | Determined that, for purposes of the cost-benefit analysis, the monetary value of emissions savings for natural gas is $0.95/MMBtu based upon the 2001 Energy Efficiency Assessment. |
| **Florida** | Adopted an "enhanced TRC test", which stopped short of assigning an economic value to carbon emissions, but allowed electric utilities to furnish their own input assumptions regarding the value of carbon emissions for the enhanced TRC test. Those assumptions ranged from $25 US to $49 US per ton by 2019. |

[38] Descriptions of these inputs are available in documentation from the Minnesota Department of Commerce's Office of Energy Security.[38]

For purposes of comparison, the market price established by the Regional Greenhouse Gas Initiative ("RGGI")[39] in its December 2009 auction was slightly more than $2 US per ton. More stringent legislation directed at carbon reductions comparable to those discussed in Copenhagen are expected to lead to U.S. carbon pricing in the $25 US/ton range by 2012, growing to $37 US/ton in 2020, as reduction targets increase.

Estimating Natural Gas Commodity Costs

The New York PSC accounts for avoided supply and interstate transportation costs in its stipulated avoided cost calculation. Gas commodity costs are forecasted using Henry Hub prices. Seasonality is incorporated into gas prices using a multiplier; price history indicates that, on average, from 1989 to 2008, winter prices in New York were 4% above the annual Henry Hub price. Summer prices were, on average, approximately 3% below the annual price.

Avoided pipeline capacity costs for the downstate portion of New York are based on projected costs for what is expected to be the next major pipeline addition in New York. Daily values are averaged to determine a winter value and a summer value, which is applied to the volume of gas conserved by DSM programs. Upstate pipeline costs utilize a similar method, but are based on forecast charges on a different pipeline. Separate local distribution charges are added to these pipeline transportation charges, and a loss factor of 4% is applied to both the commodity and local distribution margin portions.

The Energy Trust of Oregon uses conservative methods to measure avoided costs. Gas costs are derived from Northwest Natural Gas' supply forecast, and externality benefits are quantified only when a reasonable and practical method is available. However, natural gas capacity benefits are not quantified, nor are transportation and delivery losses beyond what is captured in the forecasted supply price. The Energy Trust does, however, apply a 10% credit for energy efficiency programs, "which recognizes the benefits of conservation in addressing risk and uncertainty."[40]

39 RGGI is a cooperative effort by ten Northeast and Mid-Atlantic states to limit greenhouse gases. RGGI is the first mandatory, market-based CO2 emissions reduction program in the United States. The RGGI participating states use a cap and trade system to reduce emissions of greenhouse gases.

40 Cost Effectiveness Policy and General Methodology for the Energy Trust of Oregon. February 13, 2008.

d. Recommendations

Concentric recommends that gas distributors should be responsible for calculating avoided costs and submitting them to the OEB for approval. We do not believe that the complex econometric models used in Minnesota and California are necessary in Ontario, given the added degree of complexity and the increased cost associated with such an approach. From our perspective, a limited number of input assumptions provides the necessary level of accuracy and precision for the calculation of avoided costs. Concentric endorses the Board's current approach whereby the commodity cost is updated on an annual basis, and all other avoided costs are based on a three-year program cycle. This appears to strike the proper balance between including current information for commodity costs, which tend to be volatile, while holding constant those costs which do not tend to change as frequently.

Concentric believes that the Board should consider many of the concepts outlined in the paper by the group of environmental and energy conservation experts[41] in terms of achieving more aggressive policy objectives. Specifically, Concentric recommends that the OEB consider innovative approaches to the DSM framework, including using the avoided costs associated with renewable energy resources, reducing the discount rate to place more value on savings that are expected to occur in future years, placing a monetary value on the reduction in carbon emissions that is achieved due to energy efficiency programs, and extending the effective useful life of certain DSM measures to capture the actual savings that are realized as a result of those measures.

The inclusion of avoided costs associated with renewable energy resources would significantly shift the economic analysis because those costs are typically much higher than the costs related to natural gas, water and electricity. Consequently, DSM programs that would not have been approved under a more traditional TRC analysis would become cost effective. However, if the Board adopts our recommendation to use the Program Administrator Cost test to prioritize DSM programs and measures, then including avoided costs associated with environmental externalities and $CO_2$ emissions should not change the prioritization of these programs.

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[41] "Reaching our Energy Efficiency Potential and Greenhouse Gas Objectives – Are Changes to Our Policies and Cost Effectiveness Tests Needed?", Nick Hall, et al, Prepared for presentation at the 19th AESP National Energy Services Conference and Expo, January 2009.

Rather than using the utility's weighted average cost of capital as the discount rate, the Board might consider adopting a societal discount rate similar to those in Iowa and Wisconsin, which could be based on the average yield on the Government of Canada long bond over a specified number of months. This would place more value on savings that are projected to occur in future years, and would give utilities an incentive to pursue DSM measures with longer lasting benefits. This approach would be consistent with our recommendation to adopt the Societal Cost Test, which considers social and environmental externalities in determining cost effectiveness. However, we would not recommend a negative discount rate because we believe it places too much emphasis on the value of future benefits (such as energy savings and carbon reduction) that may not materialize or persist over extended periods of time.

The Board could require utilities to assign a value to certain environmental benefits such as reduced carbon emissions. Under this approach, it would be necessary for the Board to either establish the value of carbon emissions or seek guidance from an outside expert, the regulated utilities, or the federal or provincial government in establishing the value of carbon emissions. Once a carbon price is determined, the Board could then direct gas distributors to include that value in their avoided cost calculations. Based on Concentric's survey of other jurisdictions, a price in the range of $15/ton to $25/ton would be consistent with the value placed on carbon emissions elsewhere. The following figure shows the approximate customer rate impact of various carbon prices.

**Figure 1: Customer Rate Impact of Carbon Prices**

**(All $ CDN)**

| **CO2(e) Cost Imposed (per ton)** | **$10** | **$15** | **$20** | **$25** | **$30** |
|---|---|---|---|---|---|
| Approx. Bill impact [1] | 4% | 6% | 8% | 10% | 12% |
| Bill impact $/GJ [2] | 0.535 | 0.808 | 1.080 | 1.350 | 1.620 |
| Bill Impact ($/mmbtu) [2][3] | 0.564 | 0.852 | 1.139 | 1.424 | 1.709 |
| Bill Impact $ [2] | $50 | $75 | $100 | $125 | $150 |
| Bill impact ($/m3) [4] | 0.020 | 0.031 | 0.041 | 0.052 | 0.062 |
| Bill impact ($/1000m3) | 20.491 | 30.927 | 41.364 | 51.705 | 62.046 |
| | | | | | |
| [1] Impact on small commercial; this comes from Terasen: | | | | | |
| http://www.terasengas.com/_AboutUs/Newsletters/Solutions/CarbonTaxBC.htm | | | | | |
| [2] From Terasen Gas Customer Advisory Council & Resource Planning Stakeholder Workshop | | | | | |
| [3] http://wiki.answers.com/Q/What_is_the_conversion_factor_from_MMBtu_to_GJ | | | | | |
| [4] http://bioenergy.ornl.gov/papers/misc/energy_conv.html | | | | | |

Concentric recommends that, if the OEB determines that it wishes to assign an economic value to avoided carbon emissions, the issue may require further research and analysis in order to ascertain a more accurate and precise value based on the expected form of carbon regulation in Ontario.

## X. ISSUE #3: DSM INPUT ASSUMPTIONS/PARAMETERS

a. Existing DSM Framework in Ontario

The input assumptions used in the existing DSM framework were established in the 2006 generic DSM proceeding. In that proceeding, the Board concluded that it was appropriate to have a common list of input assumptions and common values. These assumptions, with the exception of free rider rates, were replaced by the assumptions developed by Navigant in the EB-2008-0346 consultation. In April 2009 the distributors were directed by the Board to use the input assumptions developed by Navigant for their 2010 DSM plans. Data is provided for 58 measures covering the residential, commercial, multi-family residential and low-income market segments. For each technology, the following assumptions are provided:

- Description of the efficient technology
- Description of the base-case
- Decision type (new, retrofit, removal, etc.)
- Target market
- End use (i.e. space heating, water heating, etc.)
- Applicable codes, standards and regulations
- Natural gas, electricity and water savings
- Incremental equipment & O&M costs of efficient measure (as compared to base measure)
- Effective useful life (how many years the savings for the efficient measure are expected to last)
- Customer payback period to recover cost of efficient measure based on natural gas savings only
- Current penetration rate/market share of each measure
- Description / rationale used to determine the current penetration level of the efficient measure in the target area, or the current market share of the efficient measure in the target area.

According to Navigant's report, the updated measures were developed using the following process:

- Identify measures to be reviewed and updated through review of measures approved in the generic DSM hearing, subsequent utility submissions and other relevant studies;
- Research and analysis on measures and input assumptions through a review of current studies pertaining to the identified measures; literature review to identify assumptions for the same measures in other jurisdictions; assessment of the potential impacts of changes

in regulations and standards; and, simulation of savings using energy-use simulation software.

- Prepare substantiation sheets documenting assumptions for each measure, based on the research conducted.
- Update substantiation sheets based on stakeholder comments. Draft input assumptions were issued by the Board for stakeholder comment, and then updated by Navigant based on the comments received.

b. Stakeholder Comments

A variety of different stakeholders, including ratepayer advocates, environmental interests, and both gas utilities supported the concept of a process for seeking OEB approval of DSM technologies and input assumptions. Several stakeholders emphasized the importance of encouraging their advice and involvement in the development of these DSM metrics, targets and technologies, while others noted the importance of incorporating guidelines that require distributors or a third party auditor to provide detailed evidence and justification for deviating from the input assumptions approved by the Board.[42]

In March 2009, nine Ontario stakeholders[43] filed joint comments in response to Navigant's Draft report, *Measures and Assumptions for Demand Side Management (DSM) Planning*. Among the issues raised by these stakeholders were a variety of technical provisions and calculations pertaining to individual DSM programs. In addition, these groups raised several concerns with the overall approach to input assumptions, which broadly apply to many of the DSM programs and technologies assessed in Navigant's report.

The first objection mentioned by the group of stakeholders is whether input assumptions should be included for measures that are not associated with any utility programs. Because the measure could be promoted in a variety of different ways even if it were to be part of a new program, the conservation effect could change significantly. The stakeholders suggest that the Board establish a policy not to publish prescriptive assumptions for measures without a corresponding utility program.

[42] Stakeholder comments regarding free ridership are presented under Issue #4.

[43] The organizations involved in this cooperative effort include the Building Owners and Managers Association (BOMA), the Consumer Council of Canada (CCC), the Canadian Manufacturers and Exporters (CME), the Green Energy Coalition (GEC), the Industrial Gas Users Association (IGUA), the Low-Income Energy Network (LIEN), London Property Management Association (LPMA), Pollution Probe, and the Vulnerable Energy Consumers Coalition (VECC).

Stakeholders raised a concern with the application of a universal set of input and performance assumptions to certain technologies whose benefits arguably depend on a variety of factors that differ from site to site. Customer variability is defined as "variability associated with differences in customer usage patterns."[44] As the stakeholders point out, this type of variability can be adequately addressed using empirically developed averages. An example of customer variability that can be controlled is a high-efficiency water heater. While the relative benefits of such an appliance may differ in different geographies and in different buildings, an average level of performance or savings can be easily established and applied across the province to customers of both gas utilities.

The conservation effectiveness of some program measures, however, may vary substantially from one installation to the next. "Savings can be highly variable depending on how the measure is installed, how aggressively opportunities for sealing leaks are pursued, which buildings are targeted, etc." For programs that are particularly susceptible to this kind of variability, stakeholders recommend that the OEB prohibit the use of prescriptive input assumptions. In their place, these programs should be measured by particular performance metrics (for example, air leakage reduced through a home envelope-sealing program). The stakeholders note that the Navigant report includes such measures for some programs, but they would extend such measurement standards to others as well.

Finally, the stakeholders raised the issue of measuring the useful life of custom measures, which has been an important issue in the past. This issue is raised in the context of several different DSM measures, including situations in which operating hardware with useful life remaining (e.g., a conventional showerhead) is replaced by a newer, more efficient model. In such situations, the baseline against which savings are compared would have to change when the original hardware would have required replacement as a matter of course. It is the stakeholders' collective opinion that if the Board intends to apply a set of input assumptions for the durability of custom measures, a third party should be contracted for the purpose of assessing appropriate values.

[44] Neme, Chris, Nick Lange, and Kai Millyard. *Comments on Navigant's Draft Gas Measure Characterizations.* March 13, 2009. This report was prepared by the Vermont Energy Investment Corp. for the nine organizations that combined resources to respond to Navigant's report on input assumptions.

Broader issues of concern to stakeholders in addition to the prescriptive assumption values are the timing and process by which input assumptions are updated. The stakeholders favor transparent processes that include opportunities for stakeholders to present comments and participate in a decision-making proceeding. Enbridge feels that the DSM planning process it has used to involve the public during the past decade provides ample opportunities for stakeholders to provide input and advice to the utilities. The utility feels that changes instituted by the Board for the 2010 planning process are clear improvements.

c. Approach in Other Jurisdictions

Method for Establishing Input Assumptions

Input assumptions used to calculate the energy savings associated with a conservation program are generally developed using one of three models. The first option is for the regulatory agency to allow each utility to provide its own input assumptions when filing a proposed conservation plan. In this scenario, the utilities are required to explain how they arrived at these assumptions and to justify their use. As with all aspects of a proposed conservation plan, these inputs must be approved by the regulatory agency. Some of the jurisdictions surveyed have designated a third-party administrator to deliver conservation programs. In such cases, a second option is to allow these third-party administrators to develop the input assumptions with the regulatory agency maintaining oversight authority. The third option entails having the regulator itself develop and distribute a standardized set of input assumptions to be used by all utilities in calculating the energy savings associated with particular conservation programs. All three models for the development of input assumptions regularly involve the assistance of outside consultants and/or contractors. Regulators in six of the jurisdictions reviewed for this report allow utilities to submit their own input assumptions, two have designated a third-party administrator to deliver programs and develop input assumptions, and five employ standardized input assumptions developed by the regulator.

Input assumptions ordinarily provided with DSM plans include the useful life of equipment to be installed, the incremental cost of the new technology, an assumed free-ridership rate, the payback period, and the annual resource savings (i.e., gas, electricity, water) associated with the new technology. Gas savings are typically measured as a comparison between the new device and a generic baseline technology being replaced. For example, the savings associated with a new condensing boiler are calculated by comparing the forecast fuel consumption for that appliance to the consumption that would be expected for a non-condensing boiler.

<u>How Frequently Are Input Assumptions Updated?</u>

Regardless of which party is responsible for developing the inputs, these assumptions are constantly updated as actual program impacts are evaluated and reported. Ensuring that input assumptions are derived from the best available data is critical for efforts such as measuring program performance against policy goals and, where offered, the calculation of performance incentives. All of the jurisdictions analyzed in our research conduct program evaluations on a regular basis, in part, to provide additional data to continuously refine the input assumptions. The majority of jurisdictions surveyed update their input assumptions on an annual basis, while others, such as Quebec and New Jersey, re-evaluate their input assumptions every few years.

However, updating input assumptions on an annual basis is a costly endeavor, and can add to the financial burden faced by customers. In order to constantly update the input assumptions employed, resource-intensive and expensive program evaluations must be conducted. The need for regular program evaluation must be balanced with maintaining fair and reasonable rates for natural gas customers.

<u>Impact on Financial Incentives to Utilities</u>

In jurisdictions where financial incentives are offered to utilities, the constant re-calculation of input assumptions, and therefore energy savings, leads to earnings uncertainty for utilities. In such jurisdictions, utilities' strategic plans include revenue and earnings projections from conservation program achievements. When the input assumptions which form the basis of these revenue and earnings projections are constantly changing, it becomes difficult for utilities to treat conservation programs as a predictable part of their business. Regardless of the frequency of updating, the input assumptions must be completed in a timely manner to avoid program or earnings disruptions.

Further, if the program evaluation process is highly intensive and rigorous, it can cause significant delays in updating input assumptions and timing difficulties in calculating financial incentive payments. For example, under California's Risk-Reward Incentive Mechanism ("RRIM"), utilities are entitled to a financial reward based upon the percentage of pre-established conservation goals achieved. Conservation programs are approved for three-year cycles, with utilities submitting interim earnings claims after the first and second years and a final true-up claim after the third program year all based on verified energy savings. For the 2006-2008 program cycle, the interim earnings claims were intended to be submitted and approved based on a Verification Report of the past program year issued each August. The Verification Reports serve to update the Database for Energy Efficiency Resources (DEER), which is California's central database of input assumptions used to calculate energy savings based on actual program impacts. Due to the rigorous nature of these program evaluations and the aggressive timeframe in which they were to be completed, the Energy Division was delayed in completing the 2006-2007 Verification Report. Instead of being issued in August 2007, the 2006-2007 Report was not released until February 2008. Consequently, natural gas utilities were unable to submit their interim earnings claims and could not realize the RRIM in 2007 as expected. Although this is an isolated example, it demonstrates the potential risks involved with updating input assumptions.

d. Recommendations

The development of input assumptions is a complicated and highly technical process based on engineering assumptions for each specific technology. Concentric endorses the Board's current approach of developing a common set of input assumptions with the assistance of an independent consultant. However, if the gas distributors wish to deviate from these input assumptions, we believe that they should be allowed to file information that would support their assumptions. The input assumptions that were recently developed by Navigant Consulting reflect significant input from stakeholders. As the OEB continues to gain more experience with DSM programs, we would anticipate that material changes to input assumptions would occur less frequently. Therefore, concerns about the cost of maintaining such information should be mitigated to some extent. However, as new energy efficiency technologies are developed, it will be necessary to continuously develop new input assumptions for those particular DSM measures.

There is considerable debate concerning whether input assumptions should be locked in during the program cycle or updated to reflect the best available information. From Concentric's perspective, the Board should continue to update input assumptions to reflect the best available information based on the Evaluation Reports. This practice is consistent with the approach taken by the majority of other jurisdictions in our research survey. The advantage of this approach is that the Board will be better able to measure programs success against policy objectives when input assumptions are updated frequently. Another advantage is that the Board will be relying on the best available information for purposes of determining the lost revenue adjustment mechanism and the financial incentive for the utility.

The primary disadvantage to frequent updates of input assumptions is cost. However, since the OEB has significant experience with DSM programs, Concentric would anticipate that the majority of changes to input assumptions would be refinements rather than major overhauls. Therefore, we would not expect the cost of frequent updates to be as significant in Ontario as it might be for a less mature DSM framework. Further, the information gathered from the annual Evaluation Reports should be very useful in making minor revisions to input assumptions based on empirical evidence, especially on issues such as free ridership.

## XI. Issue #4: DSM Adjustment Factors

### a. Existing DSM Framework in Ontario

Under the existing framework established in the 2006 generic DSM proceeding, total resource costs for DSM programs are adjusted for certain factors. Changes to some of these adjustments were proposed as part of the Draft DSM Guidelines, in addition to the introduction of a new adjustment for spillover. A brief summary of the OEB's current policy approach to each of these adjustments, as well as the proposals as part of the Draft DSM Guidelines is outlined below:

> Free Ridership: A free rider is a "program participant who would have installed a measure on his or her own initiative even without the program."[45]
>
> Under the existing framework, free ridership rates were approved by the Board as part of the input assumptions list approved in the 2006 generic DSM proceeding.
>
> The Draft DSM Guidelines clarified that in determining the overall savings of a DSM program, free ridership participants should be excluded from the benefits attributed to the program. Similarly, the equipment costs associated with these participants should be excluded from the cost side of the equation. However, all the utility program costs associated with free riders would be included in the TRC analysis.
>
> The Draft DSM Guidelines also proposed a change regarding the development of free ridership rates. Specifically, instead of the rate being approved in advance by the Board for a particular measure or technology, program-specific free ridership rates would be proposed by the distributors. The rationale was that the design of a program and the specific customer segments being targeted can influence free-ridership. Distributors would be expected to update the free ridership assumptions on an annual basis as part of their on-going evaluation and audit processes.
>
> Attribution of Benefits: Attribution is not an adjustment to the TRC test per se, but it is important in the calculation of the Lost Revenue Adjustment Mechanism, the Shared Savings Mechanism, and other financial incentive claims.
>
> Under the existing framework established in the 2006 generic DSM proceeding, in cases where the gas distributor has partnered with a non-rate regulated third party, the attribution of benefits is determined according to whether the distributor can

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

demonstrate that its role was "central" to the program. The "centrality principle," as expressed by the Board in prior decisions, dictates that the distributor plays a central role if the distributor initiated the partnership, initiated the program, funded the program, or implemented the program. Specifically, the distributor may claim 100% attribution of benefits if the distributor can show that its financial contribution is greater than 50% of program funding, or where the distributor initiated the partnership, initiated the program, or initiated implementation of the program. In cases where the gas distributor partners with an electricity distributor, the gas distributor may claim all benefits associated with gas savings in their franchise areas. Other benefits, such as water savings, must be allocated between the gas and electricity distributor proportionally based on the dollar value of gas and electric TRC savings.

As further clarified in the Draft DSM Guidelines, a fundamental issue for the evaluation of DSM programs is whether the effects observed after the implementation of a distributor's DSM activity can be attributed to that activity or result from the activities of others.

<u>Persistence of Savings:</u> Persistence is a measure of how long a DSM measure is kept in place by the customer. A lack of persistence can have very significant effects on overall net program savings estimates.

Under the existing DSM framework, persistence is assumed to be 100%.

The draft DSM Guidelines propose that distributors would be expected to address persistence of savings in their next generation DSM plans and program evaluations There is a need for consideration of long-term retention, technical degradation, and persistence of savings, in particular, for programs with significant budgets and savings.

<u>Spillover Effects:</u> Spillover effects are not addressed as part of the existing DSM framework. The draft DSM Guidelines defined spillover as customers that adopt energy efficiency measures because they are influenced by a distributor's program-related information and marketing efforts, but do not actually participate in the program. As a result of these spillover customers in the distributor's franchise area, the distributor would collect less revenue due to lower demand for natural gas and the TRC savings could be under-estimated, which could affect the SSM claim. The draft DSM Guidelines proposed that distributors provide the Board with clear and convincing evidence that quantifies the effect of spillover on DSM program savings and the distributor's revenues.

b. Stakeholder Comments

Free-Ridership

Both gas utilities believe that free ridership should be measured and verified on a multi-year cycle rather than annually. Environmental representatives concur with the utilities with respect to free rider effects, and propose that a specific provision be included in the framework stating that, for new programs for which no free rider information is available, a 30% temporary rate for the program should be applied for up to three years, at which point a more accurate assessment can be made. Other stakeholders observe that a more frequent and rigorous review of free rider assumptions is crucial to ensure that utilities are not rewarded for outcomes that are not the direct result of utility programs.

Spillover Effects

Both gas utilities believe that spillover effects should be measured and verified on a multi-year cycle rather than annually. However, environmental groups believe that spillover effects do not represent a benefit to ratepayers or society and suggest that to avoid a windfall for the utilities, the inclusion of spillover in the assessment of DSM programs must be paired with an adjustment to the TRC reward curve to compensate for the adjustment. Most ratepayer interests are concerned with accurately demonstrating spillover effects, and contend that the Board should not allow utilities to inflate TRC savings or claim LRAM or SSM rewards unless the utility can provide a precise measure to quantify spillover.

Persistence

Enbridge suggests that no changes be made to the existing persistence methodology, which it claims benefits gas distribution ratepayers compared to the persistence standard that is applied to electric utilities in Ontario.

Attribution

Union states that the proposed attribution rules will give it confidence to develop programs jointly with other organizations. However, other stakeholders are not satisfied with the attribution provision, and find particular fault with the "centrality" principle. They believe that credit for conservation should be applied only on the basis of proportional financial support for a given program.

c. Approach in Other Jurisdictions

Sixteen of the 20 jurisdictions reviewed in our survey require that natural gas distributors offer ratepayer-funded energy efficiency and conservation programs. Of those sixteen jurisdictions, the majority acknowledge that not all of the measured impacts on energy consumption are attributable to energy efficiency and conservation programs.

In order to account for energy savings not attributable to utility conservation programs, nine of these jurisdictions, including all Canadian provinces analyzed, make adjustments to the gross impacts measured, or the total energy savings realized in a given period without consideration for attribution. All nine jurisdictions make downward adjustments to their gross impact measurements to account for free-ridership. Five of these nine jurisdictions also make upward adjustments to their gross impact measurements to incorporate spillover effects. The Canadian jurisdictions tend to focus solely on corrective adjustments to account for free-ridership, with no adjustments made for spillover effects. Certain states (e.g., Massachusetts) periodically contract independent consultants to conduct comprehensive evaluations of the free ridership assumptions that are associated with programs offered in the state.

Among these jurisdictions, gross energy savings are typically converted to net impacts using multipliers representing the non-programmatic impacts. Oregon applies separate adjustment factors for free-ridership and spillover to gross energy savings.[46] New York combines the effects of free-ridership and spillover into a single factor, with the savings from each program measure being multiplied by 0.90 to arrive at net energy savings attributable to the conservation program.[47]

Several jurisdictions look beyond free-ridership and spillover, making additional adjustments to gross impact measurements. In Connecticut and Wisconsin, an installation rate multiplier is included in the calculation of net energy savings to account for measures that were purchased or delivered, but never installed. Oregon and Wisconsin also conduct engineering reviews of reported

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46 Energy Trust of Oregon, True Up 2009: Tracking Estimate Corrections and True Up of 2002-2008 Savings and Generation, May 6, 2009, at 4.

47 New York Department of Public Service, *New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs*, March 2009.

savings, resulting in an engineering adjustment factor. Iowa requires that gas distributors make an additional adjustment to account for the persistence of savings from each program measure.

In three other jurisdictions, while it is acknowledged that not all of the gross impacts measured are attributable to utility conservation programs, no adjustments are made to gross energy savings for specific reasons. In California, the PUC does not make adjustments to the gross energy savings, opting instead to look at "total market gross,"[48] which represents the total amount of energy saved regardless of originator; savings which would have been realized even without the existence of utility programs are not discounted. The California PUC's rationale is that this will improve the understanding of the full impact of the measures installed under the utilities' conservation programs. Similarly, Washington does not adjust gross impact measurements for free-ridership or spillover, but avoids delivering windfall profits to utilities by acknowledging the existence of such effects and only allowing utilities to recoup 90% of the deferred revenue associated with conservation programs.[49] New Jersey does not adjust gross savings to account for non-programmatic factors, and justifies this by assuming that the negative effect of free-ridership and the positive effect of spillover are equal in magnitude, thus canceling each other out.

In Great Britain, while no adjustments are made to gross energy savings per se, natural gas distributors with at least 50,000 customers are each assigned a target for carbon equivalent emissions reduction that is to be achieved through energy efficiency and conservation. In order to claim credit for emissions reductions, a gas distributor must prove that such savings are "in addition" to other applicable legal requirements or programs and must demonstrate that any measure for which they intend to claim emission reduction credit would not have been installed had it not been for their conservation program. This additional criterion is similar in nature to the OEB's "centrality principle."

### d. Recommendations

There is considerable debate regarding the treatment of adjustment factors in Ontario, and there is disparate treatment across the jurisdictions reviewed in our research. The primary consideration is

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[48] California Public Utilities Commission (CPUC), *Energy Efficiency and Conservation Programs: Progress Report to the Legislature*, July 2009.

[49] Washington Utilities and Transportation Commission, Docket No. UG-060256, Order 6, August 16, 2007.

balancing the tradeoff between the desire for accuracy and precision with the cost, time and ability to measure and evaluate these factors. Concentric believes that our recommendation to focus on market penetration of DSM technologies reduces the importance of adjustment factors in Ontario because market penetration is more readily measured than consumer behavior. However, there will continue to be concerns about whether that market penetration is the direct result of energy efficiency and conservation programs, or whether it would have occurred regardless of those efforts.

NRRI has indicated that an effective DSM framework should account for the inclusion of free rider participants. Likewise, stakeholders view the issue of free ridership as very important to the overall accuracy and transparency of energy efficiency programs in Ontario. While Concentric agrees with this perspective, we believe that accurate measurement of free ridership and spillover are particularly troublesome. In terms of free ridership, Concentric observes the significant differences in free ridership that the gas distributors assume for different DSM technologies. The Navigant Consulting report was not able to provide estimates of free ridership for any of the DSM technologies and measures to be implemented in 2010 because the design of the DSM program and the specific targeted customer segments can influence the rate of free ridership.[50] Navigant ultimately concluded that free ridership is most accurately determined after the fact based on program evaluations. An important consideration is the cost associated with evaluating and measuring the free ridership rate for each specific DSM program or measure. We share the concern of ratepayer advocates that the desire for precision and accuracy can be very expensive and resource intensive, and we believe the Board should be cognizant of this tradeoff for all of these adjustment factors.

Although many jurisdictions attempt to measure free ridership, we believe it is significant that many others (including California, Connecticut, Minnesota, New York, New Jersey, and Wisconsin) do not. Concentric believes there is merit in simplifying the controversy over free ridership by either assuming that free ridership is offset by spillover, unless a specific program can be reliably shown to deviate from this assumption, or by multiplying reported energy savings by a designated factor (e.g., New York uses 90%) to adjust for effects that are not attributable to DSM. However, if the Board determines that it would like to include free ridership as an input assumption, then we agree with Navigant Consulting that this would be best accomplished by relying on empirical data from the

[50] "Measures and Assumptions for Demand Side Management (DSM) Planning," Navigant Consulting, Inc. presented to Ontario Energy Board, April 16, 2009, at 10.

program evaluation reports, or by relying on evidence from other similar jurisdictions as it becomes available.

Attribution of benefits is another controversial adjustment factor because it is very difficult to assign credit for energy savings. Concentric is concerned that the centrality principle currently used by the OEB gives too much credit to gas distributors for DSM programs. Concentric recommends that, rather than attributing 100% of the benefits to gas distributors that satisfy the centrality principle, as the default, the utilities should provide evidence supporting any percentage greater than that actually spent by the utility. Otherwise, the OEB should assign a percentage of credit to the utility based on the percentage of total dollars they spent on designing, developing and delivering the joint DSM programs in question. We believe this would more equitably attribute benefits to gas distributors than under the existing DSM framework.

Persistence is an important measure that examines whether the customer is continuing to use the more efficient technology. Concentric agrees that persistence should not be assumed at 100%, as in the current DSM framework. We recommend that persistence be determined from the technical input assumptions and the annual evaluation reports. If gas distributors wish to deviate from the level of persistence established in the evaluation reports, they should be required to file evidence with the Board to support a different adjustment factor. Finally, in their DSM plans, utilities tend to use a useful life that for certain DSM measures that is shorter than the actual engineering life, which may understate the long-term benefits of these measures. In response, the Board might consider extending the useful life of certain DSM measures in order to more accurately reflect the actual savings produced by those technologies. For example, the Board might explore extending the useful life of replacement windows, attic insulation and new building envelopes because the future benefits for those measures may have been understated.

## XII. Issue #5: DSM Program Design

### a. Existing DSM Framework in Ontario

The DSM market in Ontario is relatively mature, with the Board having first required demand side management programs for natural gas distributors in 1993. Both Enbridge and Union have significant experience with developing and delivering DSM programs to different market segments, including mass market programs to residential and small commercial customers and custom programs to large commercial and industrial customers. Further, the utilities have been responsible for addressing the unique DSM requirements of low-income customers in Ontario. In addition, gas distributors have market transformation programs which are intended to alter gas consumption patterns through customer education or long-term behavioral changes. The gas distributor must determine whether the proposed DSM program will produce the desired reduction in gas consumption at an affordable cost. DSM programs must also be designed to attract sufficient customer participation so that the forecasted benefits are actually realized.

Both Enbridge and Union offer energy efficiency audits and other programs designed to address all customer classes including residential, small business, commercial, and industrial gas users. In addition, there are programs designed for specific kinds of structures including single and multi-family residential buildings, new or existing commercial facilities, etc. Generally speaking, the utilities offer the following types of programs: 1) Prescriptive resource acquisition (i.e., assistance with the purchase of high efficiency appliances, etc.); 2) Custom resource acquisition (i.e., custom services to commercial buildings such as hospitals, hotels, schools, agricultural facilities, etc.); 3) Market transformation programs; and 4) Low-income programs.

Resource acquisition programs refer to those which involve installation of energy efficient equipment. For residential customers, these programs are primarily oriented toward rebates for installing Energy Star appliances, programmable thermostats, efficient furnaces and hot water heaters, window replacement and attic insulation. Programs designed for small businesses include incentives to invest in efficient devices such as low-flow pre-rinse valves for agricultural and grocery customers, air door heat containment systems, or kitchen ventilation systems for foodservice customers. For the most part, programs for new and existing commercial buildings are focused on the purchase and installation of efficient HVAC technology. Because of the unique nature of industrial customers, solutions for those customers tend to be custom designed measures.

Market transformation programs are defined as those that (a) seek to make a permanent change in the market for a particular measure, (b) are not necessarily measured by the number of participants, and (c) have a long time horizon. Lost opportunity markets are those that focus on DSM opportunities that will not be available, or will be substantially more expensive to implement in a subsequent planning period, such as markets where equipment is being replaced or new buildings are being built. The gas distributor must demonstrate that market transformation programs are successful in terms of changing consumption patterns across a wide range of customers. It can be rather difficult to provide definitive evidence that the DSM program is responsible for the reported results, which makes evaluation and measurement of program results very important to both regulators and interested stakeholders.

In approving the partial settlement in EB-2006-0021, the Board noted that parties to the settlement accepted that low-income customers faced unique barriers to access DSM programs. Accordingly, the parties agreed that it would be appropriate to establish a minimum amount of spending on targeted low-income customer programs in the residential rate classes of both gas distributors. Therefore, each utility was directed to spend a minimum of $1.3 million, or 14% of each respective utility's residential DSM program budget, whichever is greater. This amount was increased by the budget escalation factor for each utility (i.e., 5% for Enbridge and 10% for Union) in the second and third years of the plan. Each of the utilities may develop appropriate eligibility criteria for low income residential programs, and each utility agreed to consult with the Vulnerable Energy Consumers Coalition ("VECC") regarding the development of eligibility criteria and low-income program parameters. Settling parties generally accepted that criteria presently used by various levels of government for the purposes of determining low income eligibility may be appropriate for use by the utilities.

As established in the 2006 generic DSM proceeding, gas distributors engage and seek advice from a variety of stakeholders and experts in the development and operation of their DSM programs. Distributors are permitted to determine the stakeholders that they will engage based on the goals and objectives of the program. However, all intervenors in the distributor's most recent rate case are entitled to participate in the consultative meetings.

With respect to the use of input assumptions in the context of DSM program design, distributors are required to design, screen and evaluate DSM programs using the best available information known to them at the relevant time. New information should be incorporated into program design and implementation as soon as possible.

b. Stakeholder Comments

There was very little, if any, discussion of resource acquisition programs in the stakeholder comments reviewed by Concentric. Two stakeholders included a brief discussion of "deep" versus "shallow" conservation programs, particularly in the context of programs designed to serve low-income customers. Several stakeholders that participated in the Conservation Working Group suggested that additional efforts should be made to pursue deep conservation programs for low-income customers. Other stakeholders mentioned that both gas distributors have directed more resources to deep program efforts in recent years, thereby increasing the number of such measures supported.

Other stakeholders have raised concerns with respect to market transformation programs. The most common of these concerns pertains to measuring the results of market transformation activities. Several organizations commented that specific, measurable, and most importantly, verifiable targets are crucial for a fair and equitable market transformation program. These stakeholders feel that incentives for market transformation programs should only be paid when meaningful change has occurred in the markets.

As mentioned above, more than one organization expressed concern that attributing shifts in a market to programs operated by the distributors would be very challenging, if not impossible. (This concern regarding attribution is mentioned in Section 5.3.2 of the OEB Staff Discussion Paper.) Finally, several stakeholders do not believe that gas distributors are well-suited, or even capable, of transforming markets. One group indicated that social change is the purview of government, not profit-oriented private enterprises.

Certain stakeholders have emphasized the unique nature of the low-income market, and have commented that significantly different program designs are needed relative to those applicable to other market segments. For example, one stakeholder emphasizes that DSM programs should be designed to target low-income residents throughout the utilities' service areas, and that utility programs should address low-income housing units in a holistic manner (i.e., all opportunities to enhance energy efficiency should be addressed simultaneously). However, certain ratepayer advocates are less supportive of programs that are specifically targeted at individual populations, because they contend that utilities should not be expected to deliver social objectives.

The gas utilities have expressed concern that programs designed to reach low-income residents tend to have lower quantifiable TRC net savings because of the inability to adequately capture social benefits, and because of the long period of time required to achieve measurable results from such programs. Certain ratepayer interests argue that DSM targets should be set with the singular objective of achieving energy efficiency goals, and that low-income programs should be reviewed using the same screening and evaluation criteria as all other DSM programs.

c. Approach in Other Jurisdictions

All of the jurisdictions reviewed in our research that require utilities to administer natural gas DSM programs also require those utilities to address the needs of different market segments, such as mass market programs for residential and small commercial customers, tailored programs for large commercial and industrial customers, unique programs for low-income and elderly customers, and market transformation programs that benefit customers across all classes.

Resource Acquisition Programs

Utilities in each of the jurisdictions included in our research offer resource acquisition programs which are similar in nature to those offered by Enbridge and Union in Ontario. For more information on specific DSM programs and measures, please refer to Appendix A, which contains descriptions of DSM programs offered by utilities in the U.S., Great Britain, New Zealand and Australia.

Market Transformation Programs

Market transformation programs are intended to alter gas consumption patterns through customer education or long-term behavioral changes. These programs include a wide variety of different approaches, which range from offering conferences and tradeshows for building contractors to radio advertising targeted to gas customers encouraging them to reduce energy consumption by X% per year over the next ten years by installing more energy efficiency space heating to education materials distributed to schools to teach children about saving energy and protecting the environment.

National Grid, the U.K. based gas and electric company offers several initiatives through its gas and electric subsidiaries in the U.S. It's "Power of Action" program is a web-based and mass media outreach effort designed to encourage consumers to reduce their energy consumption 3% per year for the next 10 years. The program promotes energy efficiency, conservation, and natural gas conversion where appropriate. Among these programs offered through their MassElectric subsidiary is the Building Operator Certification initiative. This is a competency-based training and verification program for building operators designed to improve the energy efficiency of commercial and industrial buildings. Building operators can earn certification by attending training sessions and completing project assignments in their facilities. The training and certification initiative is designed to replicate a program developed in the Northwest United States by the Northwest Energy Efficiency Council. That initiative is sponsored by several gas and electric utilities in the Northeast region and administered by the Northeast Energy Efficiency Partnerships.[51]

On a national basis, a number of gas and electric utilities have partnered with the ENERGY STAR program based on an energy efficiency standard developed by the Environmental Protection Agency for new home construction. Energy Star qualified homes are at least 15 percent more energy efficient than homes built to the 2006 International Residential Code (IRC), and include additional energy-savings features that typically make them 20–30% more efficient than homes built to local residential construction codes. The EPA's initiative is supported in Massachusetts by a consortium of utility companies and energy efficiency service providers who collaborate to promote the benefits

[51] www.powerofaction.com/about/, www.nationalgridus.com/Masselectric/business/energyeff/energyeff.asp, and www.theboc.info/ne/

of energy-efficient, high performance homes. Builders are eligible for financial incentives for meeting these standards.[52]

Southern California Edison has created a Customer Technology Application Center as a source of energy efficiency information for business owners and operators, architects and designers, operations and facility managers, contractors, engineers, or anyone wanting to learn about the latest in state-of-the-art technology for saving energy, money, and the environment. The center offers seminars and workshops in an adult-learning setting, demonstrations using displays and exhibits, technical consultations, and program and rebate information.[53] Edison also offers a comparable center focused on agribusiness.

In Great Britain, the Community Emissions Savings Programme (CESP) targets geographic zones rather than individual consumers in order to alter energy consumption patterns within an entire community. The effort requires a substantial capital investment with promising social and economic benefits that will persist far beyond the project period. Further, the obligations established through CESP are required to be 'additional' to other efficiency programs and policies. British utilities must demonstrate that the initiatives used to meet CESP targets produce results above and beyond other programs that are underway in the regions of interest in order to qualify for program compliance.[54]

<u>Low-Income Customer Programs</u>

Among the five Canadian provinces reviewed in our research sample, only Quebec explicitly requires natural gas distributors to implement DSM programs to address low-income customers. Of the 12 U.S. states surveyed, nearly all require programs that address low-income customers, with the rigor of each program varying from state to state. Among the programs outside North America that were evaluated, the only program with a specific framework for action by utilities is Great Britain's Consumer Energy Savings Programme ("CESP"), which requires utilities to meet performance goals by addressing the challenges of low-income customers.

52 www.massenergystarhomes.com/about/overview.htm

53 www.sce.com/b-sb/energy-centers/ctac/ctac.htm

54 Explanatory Memorandum to the Community Emissions Savings Programme Order, 2009. (page 14) http://www.ofgem.gov.uk/Sustainability/Environment/EnergyEff/cesp/Documents1/CESP%20Generator%20and%20Supplier%20Guidance.pdf

Quebec's low-income programs originate from the province's Energy Efficiency Fund ("EEF"). The EEF was created through an agreement between Gaz Metro and representatives from a variety of socio-economic and environmental interest groups in Quebec. The agreement was authorized by the provincial energy regulator in the fall of 2000, and has since been renewed through 2012. Gaz Metro provides cash incentives and interest-free financing support to low-income customers for a variety of projects including residential insulation retrofits, appliance replacement, etc.

Other states recognize that a host of market barriers face low-income customers, and approach programs targeting these populations accordingly. The New Jersey Department of Community Affairs (a state agency) began to collaborate with utilities on low-income programs in 2006. The arrangement was designed to ensure that certain services were provided to the low-income community, including:

- Installation of all cost-effective energy efficiency measures in customer homes
- Personalized education and counseling concerning energy efficiency opportunities
- Arrearage-reduction services, providing customers a method of paying bills on time
- Coordination with other services and agencies available to customers

In Colorado, state law requires utilities to propose methods to direct DSM resources to low-income customers. Legal requirements are modest, however, leaving most details to the utilities, including the decision to address low-income programming through direct funding, or indirectly through financial support of low-income programs administered by the state.

Among the twenty jurisdictions studied in this report, Great Britain provides what is perhaps the most unique method of addressing the challenges that face low-income residents. In Britain, the Community Energy Savings Programme Order was issued by the Office for Gas and Electricity Markets ("Ofgem") under the authority of the Gas Act of 1986, the Electricity Act 1989 and the Utilities Act 2000. CESP is a community-based program designed to bring energy efficiency measures to low-income communities that are particularly vulnerable to energy poverty. CESP is modeled closely on the pre-existing Carbon Emission Reduction Target Programme ("CERT"). Both programs promote energy conservation indirectly, through efforts to reduce greenhouse gas emissions.

Under CESP, emissions reduction targets are established for each utility based on the number of customers served. The program then identifies geographic regions within Great Britain that contain the highest densities of low-income residents as measured by the Indices of Multiple Deprivation ("IMD"). The lowest 10% of areas ranked by IMD qualify in England; in Scotland and Wales the lowest 15% qualify. CESP obligates utilities to confront energy efficiency challenges in these regions using a whole-house, neighborhood, and community approach.[55] The program is designed to promote community involvement by enabling utilities to partner with local contractors and community organizations to address efficiency challenges broadly.

The selection of specific DSM programs and measures is largely the prerogative of the utility under CESP, but for each concept pursued (e.g., home insulation, efficient light bulbs, replacing water heaters, etc.) there is a pre-defined carbon score promulgated by Ofgem. The utilities may choose which programs to deploy, but they must seek approval for their programs from Ofgem. Although the utilities are permitted to pass along any and all costs of the program to their customers, it is expected that they will select the most cost effective programs by virtue of the fact that utility customers in Great Britain are able to freely choose the lowest cost gas service provider available. The competitive market provides the incentive to keep rates low and, by extension, to select the most cost effective means of reaching demand reduction targets.

California has taken the most aggressive/innovative approach to DSM programs for low-income customers. The California legislature established the Low Income Oversight Board ("LIOB") in 2001 to advise the Commission on low-income customer issues and to serve as a liaison to low-income ratepayers and representatives. The LIOB is responsible for designing and delivering energy efficiency programs to that customer group. In 2007, the Commission issued a decision that articulated a major new policy direction for Low Income Energy Efficiency ("LIEE") and California Alternate Rates for Energy ("CARE"). Specifically, the California PUC found that LIEE programs, in addition to promoting the quality of life of eligible customers, should serve as resource programs. Resources programs are those which are designed to save energy, limit the need for new power plants, and curb greenhouse gas emissions. In D.07-12-051 and in the *California Long-Term Energy*

55 http://www.ofgem.gov.uk/Sustainability/Environment/EnergyEff/cesp/Pages/cesp.aspx

*Efficiency Strategic Plan*, the Commission stated a long-term vision for the LIEE program as follows: "By 2020, 100% of eligible and willing customers will have received all cost effective Low Income Energy Efficiency measures."

The California PUC indicated that large investor owned utilities ("IOUs") were expected to file 2009-2011 budget applications that: 1) treat LIEE as a resource program by focusing on energy savings, in addition to customers' quality of life; 2) propose substantial budget increases so as to provide LIEE measures for 25% of eligible and willing customers in the 2009-2011 period; 3) emphasize long term and enduring savings, rather than quick fixes; and 4) focus LIEE programs on customers with high energy use, while continuing to serve all eligible low income participants.

In approving the large IOU's DSM budget applications for 2009-2011[56], the California PUC laid out guiding principles for low income energy efficiency programs as follows:

- IOUs shall focus on customers who have high energy use, high energy burden (i.e., ratio of their energy bills to income) and high energy insecurity (late payments, threatened service shut-off)
- IOUs shall minimize costs and greenhouse gas emissions in delivering LIEE measures to low income households. By focusing efforts on whole neighborhoods, they will be able to treat more households.
- In emphasizing the customers with high energy use, burden or insecurity, the IOUs shall not neglect low income customers with lower energy use.
- For DSM measures that fall below a 0.25 cost effectiveness level, such as certain heating and cooling measures, IOUs are required to provide additional reporting to show the cost, energy savings impacts, and related metrics. However, the goal of the LIEE program is to deliver significant cost-effective energy savings.
- IOUs are required to provide energy efficiency education – in which the utility informs and teaches low income customers about the benefits of energy efficiency – to occur close in time to installation of measures.
- IOUs shall enhance outreach to persons with disabilities, who represent approximately 20% of LIEE-eligible customers.
- IOUs have long been required to integrate their demand-side programs, but now will be required to demonstrate success based on measurable criteria.

[56] California Public Utilities Commission, Decision on Large Investor Owned Utilities' 2009-11 Low Income Energy Efficiency (LIEE) and California Alternate Rates for Energy (CARE) Applications, Decision 08-11-031, November 6, 2008, at 3-7.

- We set a 90% CARE penetration goal for all IOUs (reduced from 100% in the previous decision).

Lost Opportunity Markets and "Deep Savings"

The most aggressive DSM programs are those that use innovative approaches to alter the way energy is consumed. California is known for encouraging its utilities to pursue novel programs, which may have higher capital costs and delayed, albeit compelling, social and economic benefits. Because of the way efficiency gains from such programs are tied to other, more conventional conservation initiatives, California terms the exclusion of these deep options as 'lost opportunities'. Similarly, the tendency to pursue only the most attainable forms of energy efficiency is known as "cream-skimming":

> "Lost opportunities" are those energy efficiency options which offer long-lived, cost-effective savings and which, if not exploited promptly or simultaneously with other low cost energy efficiency measures or in tandem with other load-reduction technologies or distributed generation technologies being installed at the site (e.g., solar heating or photovoltaics), are lost irretrievably or rendered much more costly to achieve. "Cream skimming" results in the pursuit of only the lowest cost energy efficiency measures, leaving behind other cost-effective opportunities. Cream skimming becomes a problem when lost opportunities are created in the process. [57]

In order to ensure that energy efficiency programs reach their full potential, California's PUC requires ambitious goals of its utilities and encourages them to look broadly for opportunities to moderate the consumption of energy throughout their service territories:

> The aggressive annual and cumulative savings goals established by the Commission will serve to discourage cream-skimming program designs or implementation approaches that create lost opportunities. Nonetheless, Program Administrators should actively develop strategies to minimize lost opportunities, and should describe those strategies in the applications they submit for each program cycle.[58]

California's Value and Energy Stream Mapping ("VeSM") program is a unique example of this type of program. VeSM is an overhaul of an existing Southern California Edison ("SoCalEdison")

[57] California Energy Efficiency Policy Manual, Version 4.0. August, 2008.
[58] California Energy Efficiency Policy Manual, Version 4.0. August, 2008.

energy efficiency program, but with a more robust approach to gas intensive manufacturing processes. The utility recognized that energy efficiency has not been a priority for manufacturers for a variety of reasons:[59]

- Energy costs are often small relative to other costs.
- Concerns over the long-term benefits of energy efficiency savings.
- Payback periods have been long term in nature.
- Companies lack in-house expertise to implement energy efficiency improvement projects.

With this understanding, SoCalEdison has focused considerable attention and resources on these customers. The VeSM program overcomes many of the manufacturer's barriers to focusing on energy efficiency by providing companies with assistance in implementing productivity improvements to achieve rapid, substantial, long-term financial returns. Industries that SoCalGas and other California utilities have provided these services to include laundromats and a variety of food service industries.

Alternative financing arrangements are another way that municipal governments have helped homeowners to overcome the relatively high upfront cost of energy retrofits. Under these programs, which were first adopted in Berkeley, California in 2007, the municipality creates an Energy Financing District, which issues bonds to finance 20 year, low-interest loans to homeowners who want to install energy efficient technologies. The homeowner repays the loan through a small increase in their property tax. The interest rate on the loan is typically around 1% higher than the interest rate on the municipal bonds, allowing the municipality to recover the cost of administering the programs.[60]

Smart Meter Pilot Program in Great Britain

In October 2008, the government announced its intention to mandate a roll out of electricity and gas smart meters to all 26 million homes in Great Britain by 2020.[61] This would mean replacing the

[59] California 2006-2008 Energy Efficiency Programs Value and Energy Stream Mapping (VeSM) Program Concept Paper.
[60] http://www.ci.berkeley.ca.us/ContentDisplay.aspx?id=44262
[61] http://www.decc.gov.uk/en/content/cms/what_we_do/consumers/smart_meters/smart_meters.aspx

UK's 47 million gas and electricity meters.[62] The expected cost is £8.5 billion, while savings are expected to total £14.5 billion from reduced customer bills and lowered administrative costs to utilities.[63]

British Gas has received approval for a pilot program in which it will install smart meters in the homes of 50,000 gas customers. However, there are not yet any reliable estimates regarding the success of this program. One report indicated that customer bills had been reduced by 30% due to this program, but that figure has not been confirmed. British Gas is also currently working with Vodafone to install smart meters across its organization, from street retail outlets to remote radio base stations. Following a pilot trial at 700 sites, by 2010, British Gas Business will have rolled out 8,000 meters for Vodafone, which estimates an overall cost saving of £2million and 5 per cent reduction in their energy consumption.[64] The Director of British Gas smart metering said that the Company estimated energy savings from smart meters to be around 2% to 3%, which is similar to government estimates.[65]

According to Ofgem, the largest pilot underway is currently being run by Ofgem. It is, at this point, too early to draw any conclusions from the available data. The Ofgem study involves both gas and electricity meters. The most recent progress report update, which was published at the end of September 2009, states:[66]

> Since the last report, there has been significant progress in installing smart meters and progressing the trials. This will mean that future reports will contain more statistically robust results given the increased data available. The four participating suppliers; E.ON, EDF, ScottishPower and SSE are investigating the reactions to the delivery of energy use information to customers through bills, clip on visual display units, and smart meter related interventions. There are now nearly 59,000 households taking part in trials and a further 18,000 households are included in control groups (114% of the target). Nearly 17,000 households have had smart meters installed as part of the trial, many with both gas and electricity smart meters.
>
> As yet statistically significant differences in energy usage between intervention and control groups have not been observed consistently across the trials; however,

62 http://www.britishgas.co.uk/business/what-we-do/our-business/bgb-news.html (13May, 2009 - "Smart Meters to lead energy revolution, says British Gas")
63 http://www.guardian.co.uk/business/2009/dec/02/smart-meters-go-ahead
64 http://www.britishgas.co.uk/business/what-we-do/our-business/bgb-news.html (13May, 2009 - "Smart Meters to lead energy revolution, says British Gas")
65 http://www.guardian.co.uk/business/feedarticle/8837911 (Wednesday Dec 2, 2009)
66 http://www.ofgem.gov.uk/Sustainability/EDRP/Documents1/EDRP%20Progress%20Report%203%20final.pdf

further work on the data is being progressed. Until full correction of the data has been resolved the results are being treated as preliminary.

d. Recommendations

Concentric agrees with the previously-referenced NRRI publication, which indicates that DSM programs should be aligned with identified energy savings opportunities or "behavioral" problems in the market. DSM programs should be designed to emphasize those measures and technologies that contribute most to cost effective energy savings. In that regard, the market potential studies prepared for Union and Enbridge are useful in understanding which resource acquisition programs would be expected to result in the highest reduction in gas consumption for that utility. According to the Union report, the most significant opportunities for natural gas savings for residential customers are technologies that reduce space heating requirements, such as high-performance windows, programmable thermostats, and thermal envelope improvements in older homes.[67] For commercial customers, the most significant achievable savings opportunities were actions that reduce space heating loads in existing buildings (e.g., building re-commissioning, advanced building automation systems, space heating equipment upgrades and heat recovery), and actions that reduce hot water loads in existing buildings, including low-flow fixtures and water heating equipment upgrades. Building re-commissioning is a particularly large opportunity.[68] For the industrial sector, the most significant opportunities for natural gas savings are technologies that reduce gas usage for process heating, specifically, ovens, dryers, kilns and furnaces. Implementation of energy-efficiency measures in boiler systems is also a significant opportunity. Measures that improve the total plant (referred to as system wide) energy efficiency are the third most significant opportunity for industrial customers.[69]

Another guiding principle for regulators that was articulated in the NRRI publication was that the utility should prioritize its DSM programs based on which programs are expected to produce the most cost effective results. This suggests that program design should be influenced, to some degree, by the cost effectiveness of each individual program, as well as by whether the program addresses an identified savings opportunity or a recognized behavioral problem. Concentric recommends that

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67 "Natural Gas Energy Efficiency Potential: Residential, Commercial and Industrial Sectors Summary Report," prepared by Marbek Resource Consultants Ltd. for Union Gas Distribution, March 24, 2009, at 17.

68 Ibid, at 23.

69 Ibid, at 29.

the Board utilize energy efficiency potential studies from Union and Enbridge as an indicator of which DSM programs are most likely to achieve the highest energy savings because they are aligned with documented opportunities to reduce gas consumption.

It is difficult to attribute verifiable savings to market transformation programs, which are intended to influence consumer behavior and attitudes through industry conferences and tradeshows, and contractor recommendations that would increase penetration levels for the most energy efficient technologies. Concentric recommends that the Board utilize a combination of customer and vendor surveys to estimate the effectiveness of these programs, with the understanding that precise estimates of savings from market transformation programs are not attainable.

Lost opportunity markets represent an important way for gas distributors to achieve meaningful reductions in gas consumption and significant improvements in market penetration for the most efficient technologies available. Lost opportunity markets offer utilities the chance to achieve deep savings by pursuing unique, one-time opportunities to reduce natural gas consumption. Distributors should be encouraged to pursue lost opportunity markets when they become available by including the achieved program results in the calculation of the financial incentive, and the Board should allow the distributor to modify its current DSM plan in order to pursue these opportunities.

The low-income customer group presents unique challenges and opportunities for both regulators and utilities. One challenge is that the low-income resident may not be the person responsible for the utility bill, or the decision maker in terms of installing more energy efficient technologies. If there is a landlord/tenant relationship, then the landlord is most likely responsible for controlling the thermostat and for deciding whether to upgrade to more energy efficient technologies. In this situation, the gas distributor will need to develop and maintain a working relationship with the property owner. A second challenge is that, in a landlord/tenant situation, the benefits of DSM programs will inure to the landlord rather than the tenant. Concentric recommends that gas distributors and the Board continue to explore ways to address this concern because we believe that DSM programs for low-income consumers represent an important component of an effective DSM policy.

Concentric concludes that DSM programs for low-income customers should follow several guiding principles. First, the utility should identify geographic regions with the highest concentration of low-income customers. Second, the utility should primarily focus on those customers with the highest energy use and those who have a history of late payments or face disconnection. Third, in order to capture economies of scale, the utility should develop programs that serve an entire neighborhood, rather than an individual customer. Fourth, the utility should concentrate on DSM programs that provide immediate and long-term benefits, such as home weatherization and appliance replacement. Fifth, the utility should coordinate with community organizations and local contractors to modify consumer attitudes and behaviors through education. Finally, the utility should understand that serving the low-income or disabled population requires a grassroots, community-based effort.

## XIII. ISSUE #6: DSM BUDGET DEVELOPMENT

### a. Existing DSM Framework in Ontario

The current DSM budgets were approved by the Board in its August 26, 2006 decision. The DSM budget cap was developed using a formulaic approach in each year of a three-year (2007-2009) DSM plan. For the first year, the budget for Enbridge was set at $22.0 million, an increase of $3.1 million or approximately 16% from its 2006 budget. For Union, the 2007 budget was set at $17.0 million, an increase of $3.1 million, or approximately 22% from its 2006 budget.

In the second and third years of the three year DSM plan, the DSM budget for each year of the plan was determined by applying an escalation factor of 5% for Enbridge and 10% for Union to the budget developed for the immediately preceding year. The purpose of the different escalation factors for Enbridge and Union is to address the desire by some stakeholders that the difference between the level of spending by Enbridge and Union be narrowed. This formula has resulted in budgets of $23.1 million and $24.3 million for Enbridge in 2008 and 2009 respectively, and budgets of $18.7 million and $20.6 million for Union in 2008 and 2009 respectively.

Incorporated into these budgets are allocations for market transformation programs and programs for low income customers. The budget for market transformation programs was established at $1.0 million per utility per year. The budget for low income customers was established for 2007 at a minimum of $1.3 million, or 14% of each respective utility's residential DSM program budget, whichever is greater. The initial budget for low income customers was to increase by the budget escalation factor appropriate for each utility (i.e. Enbridge 5%; Union 10%) in each of the second and third years of the three year plan. In addition, each utility was to spend no less than 14% of the low-income market transformation budget on market transformation programs for low-income customers.

The existing DSM Framework also requires that an appropriate level of budgets for research shall be determined by each utility from time to time (depending upon need, market conditions, etc.) and that each utility should include a summary of its forecasted research in its multi-year DSM plan filed with the Board. The approved research budget for Enbridge for 2010 is $500,000, which is approximately 2.1% of its total DSM budget.[70] Union is authorized to spend $919,000 on research in 2010, which will correspond to approximately 4.4% of its DSM expenditures.[71]

Spending is tracked in the DSM Variance Account, which is used to "true-up" the difference between the approved budget built into rates for the year and the actual spending in that year. If spending is less than the approved budget, ratepayers are to be reimbursed. If a distributor spends more than the approved budget, it can be reimbursed up to a maximum of 15% of its DSM budget for the year.

The existing framework recognized that Enbridge's and Union's rate classes and customer classes are not identical, and as such it would not be appropriate to assign spending to each rate class based on a rigid, formulaic approach. Instead, distributors were expected to develop a portfolio of programs that would provide all customers in all rates classes and sectors with equitable access to DSM programs to the extent reasonable, and allocate the budget accordingly. To the extent that the distributor proposed a budget level for a particular sector that was significantly different than the historical level, the burden is on the utility to justify that request.

In 2009, the Board extended the existing DSM framework to 2010, including the established budget escalators. The table below provides the Board-approved DSM budgets for 2010.

**Table 13: Approved 2010 DSM Budgets for Ontario Gas Distributors**

| 2010 DSM Budgets | Enbridge | Union |
|---|---|---|
| Resource Acquisition Programs | $24,055,213 | $21,297,000 |
| Market Transformation Programs | $995,557 | $1,330,000 |
| Low-income Programs | $1,666,980 | $1,730,000 |
| (Industrial) Pilot Program | $1,250,000 | N/A |
| **Total** | **$25,050,770** | **$22,627,000** |

70 Enbridge Gas Distribution Inc. 2010 Natural Gas Demand Side Management Plan (EB-2009-0154), Exhibit B.
71 Union Gas Limited - 2010 Demand Side Management Plan (EB-2009-0166), at page 4.

On January 7, 2009, the Board extended the existing DSM to 2011 and directed Enbridge and Union to submit their DSM plans for 2011 by April 30, 2010. By extending the existing DSM framework, the 2011 DSM budgets for Enbridge and Union are estimated to be about $26 million and $25 million respectively.

The Draft DSM Guidelines propose that distributors bring forth for approval a budget for their respective DSM plans. Each distributor would be expected to justify its budget proposal based on the results of its DSM programs to date, 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 would also be expected to propose separate DSM budgets for the following: 1) Resource Acquisition programs; 2) Market Transformation programs; and 3) Low Income customer programs. Distributors also were encouraged to consult with stakeholders in developing their DSM budgets.

The Draft DSM Guidelines permitted distributors to apply for multi-year DSM funding to support better planning and management and facilitate the utilities' ability to enter into partnerships with other delivery agents. The Draft DSM Guidelines also clarified that the DSM budgets should include cost estimates for administration, evaluation, research (including market potential studies) and support.

Under the Green Energy Act, it is possible that the Ontario Energy Board could assess gas distributors for energy efficiency and conservation programs that are currently funded by taxpayers. Further, the Minister of Energy and Infrastructure is currently considering a low-income policy that might include DSM budgets for low-income customers. However, there is no further information available at this time.

b. Stakeholder Comments

Most ratepayer representatives suggested that the Board should set distributors' DSM budgets based on the specific programs sponsored by the distributors. However, representatives of environmental interests called for the Board to set aggressive DSM budgets, which could ramp up to 3% of total utility revenue over a three-year period. Union favors using 5% of distribution revenue as a benchmark for establishing DSM budgets. Enbridge argues that it would be arbitrary and not reflective of market conditions or customer needs to establish a DSM budget that was a specific percentage of utility revenue. It suggests that budgets be developed by utilities and presented to the Board with proposed DSM plans.

Certain stakeholders have expressed concerns about the process used and the time and effort needed to reconcile the often conflicting views of various stakeholder groups and natural gas utilities in the development of DSM budgets. Several stakeholders believe budget development should take place as part of a regulatory proceeding, while Enbridge favors a DSM process that is separate from conventional rate proceedings.

The debate over the length of the budget period is split into two camps: the utilities advocate a multi-year approach to promote continuity and certainty of funding to cost-effective programs. The remaining stakeholders argue that program duration should be one or, at most, two years, particularly during this uncertain economic period and in light of the Green Energy Act, which is expected to have a significant effect on DSM planning.

Several stakeholders in the Conservation Working Group ("CWG")[72] commented that the budgets proposed by the utilities for low income DSM programs (in the CWG) would produce a significant rate impact, and they recommended a range of possible solutions including firm budget caps, reductions in the number of participants and/or the estimated cost per home, and strict monitoring and evaluation of proposed programs. The utilities responded by asking the Board to be cognizant of the link between savings targets and program budgets, and by indicating that the budget cannot be reduced without a corresponding reduction in the number of low income customers that benefit from energy efficiency programs.

### c. Approach in Other Jurisdictions

Amount Spent on DSM Budget

According to the previously referenced report concerning Canadian Best Practices in DSM, an important measure of DSM expenditures is the percentage of utility revenue spent on DSM

[72] The Conservation Working Group was established by the OEB in conjunction with the Board's review of Low Income Energy Assistance Programs in EB-2008-0150. See comments at page 10 of Appendix C.

programs. The following table presents that information for the Canadian gas utilities that offer DSM programs based on 2007 data.

**Table 14: 2007 DSM expenditures, by company, as a percentage of revenue[73]**

| Jurisdiction | Utility | Year | Gross Oper Rev (000s) | DSM Expenditures (000s) | DSM % GOR | GOR less cost of gas (000s) | % of utility revenue less cost of gas |
|---|---|---|---|---|---|---|---|
| British Columbia | Terasen | 2007 | $1,751,000 | $3,100.0 | 0.18% | $622,000 | 0.50% |
| Manitoba | Manitoba Hydro | 2007 | $528,000 | $10,100.0 | 1.91% | $142,000 | 7.11% |
| Ontario | Enbridge | 2007 | $3,085,000 | $22,000.0 | 0.71% | $972,000 | 2.26% |
| Ontario | Union | 2007 | $1,811,000 | $17,000.0 | 0.94% | $655,000 | 2.60% |
| Quebec | Gaz Metro | 2007 | $1,600,000 | $14,400.0 | 0.90% | $420,000 | 3.43% |
| Saskatchewan | SaskEnergy | 2007 | $962,000 | $1,800.0 | 0.19% | $587,000 | 0.31% |
| | Average | | $1,622,833 | $11,400 | 0.70% | $566,333 | 2.01% |

Concentric has prepared comparable information for a sample of U.S. gas distributors that offer service in the states included in our survey. The following table presents that information for the U.S. gas utilities based on either 2007 or 2008 data, as noted.

**Table 15: 2007/2008 DSM expenditures, by company, as a percentage of revenue[74]**

| Jurisdiction | Utility | Year | Gross Oper Rev (000s) | DSM Expenditures (000s) | DSM % GOR | GOR less cost of gas (000s) | % of utility revenue less cost of gas |
|---|---|---|---|---|---|---|---|
| California | SoCalGas | 2008 | $4,101,000 | $68,016.0 | 1.66% | $1,260,000 | 5.40% |
| Connecticut | Southern CT Gas | 2008 | $433,613 | $2,022.0 | 0.47% | $129,596 | 1.56% |
| Iowa | Mid-American | 2007 | $890,960 | $15,813.7 | 1.77% | $406,439 | 3.89% |
| Maine | Northern Utilities | 07/08 | $49,151 | $675.4 | 1.37% | $20,178 | 3.35% |
| Massachusetts | National Grid | 2007 | $1,511,246 | $7,757.3 | 0.51% | $292,326 | 2.65% |
| Minnesota | Northern States | 2008 | $796,343 | $6,423.5 | 0.81% | $201,697 | 3.18% |
| Minnesota | CenterPoint Gas | 2008 | $1,385,652 | $8,422.8 | 0.61% | $142,066 | 5.93% |
| New York | Con Edison | 2008 | $1,702,889 | $14,000.0 | 0.82% | $705,343 | 1.98% |
| Oregon | NW Natural | 2008 | $867,539 | $9,282.9 | 1.07% | $269,045 | 3.45% |
| Washington | Cascade NG | 2008 | $104,945 | $2,382.5 | 2.27% | $29,006 | 8.21% |
| | Average | | $1,184,334 | $13,480 | 1.14% | $345,570 | 3.90% |

These tables indicate that the average Canadian gas distributor spent approximately 2.0% of utility revenue less the cost of purchased gas on DSM programs in 2007, while the ten U.S. gas distributors in our sample spent approximately 3.9% of utility revenues less the cost of purchased gas on DSM programs in either 2007 or 2008. It is important to remember that the U.S. states were selected for

73 Ibid, at 19.

74 Source: Individual company DSM filings with regulatory agencies and annual financial reports to shareholders.

our survey because they spent the most per capita on energy efficiency and conservation programs. However, this finding suggests that leading U.S. gas distributors are spending substantially more of their utility revenues on DSM programs than the average Canadian gas distributor, including those in Ontario.

Concentric also reviewed DSM spending and energy savings by customer class in order to better understand the similarities and differences between the residential, commercial/industrial and low income sectors. Our findings indicate that the U.S. gas distributors and program administrators in our sample spent an average of $45.88/dekatherm saved among residential customers, $28.60/dth saved among commercial/industrial customers, and $106.78/dth saved for low-income customers. The following table summarizes these findings for the states in our sample for which information was readily available.

**Table 16: Cost of DSM Programs for Select Utilities/Jurisdictions by Customer Class ($US/dth saved).**

| State/Utility | Period | Residential | Commercial/ Industrial | Low Income | Total |
|---|---|---|---|---|---|
| **California** | | | | | |
| SoCal Gas | 2006-2008 (Avg.) | $71.59 | $8.17 | N/A | $13.35 |
| **Oregon** | | | | | |
| Energy Trust | 2008 | $36.44 | $78.84 | N/A | $58.94 |
| **Connecticut** | | | | | |
| ECMB | 2008 | $61.26 | $44.43 | $64.35 | $59.02 |
| **New York** | | | | | |
| NYSERDA | 2006-2008 (Avg.) | $86.32 | $54.14 | $111.98 | $80.69 |
| **Washington** | | | | | |
| Cascade Natural Gas | 2008 | $24.62 | $11.35 | $68.30 | $52.84 |
| **Massachusetts** | | | | | |
| National Grid | 2006-2008 (Avg.) | $31.98 | $17.70 | $96.87 | $33.24 |
| 2010 Budget, Statewide | 2010 | $61.67 | $28.22 | $256.98 | $51.80 |
| **Minnesota** | | | | | |
| CenterPoint Gas | 2008 | $26.27 | $5.41 | N/A | $9.92 |
| Northern States Power | 2008 | $17.05 | $4.91 | N/A | $10.20 |
| **Wisconsin** | | | | | |
| Total Program | 2008 | $43.25 | $15.68 | N/A | $23.73 |
| **Iowa** | | | | | |
| Total Program | 2007 | $43.70 | $23.06 | $138.23 | $34.36 |
| MidAmerican | 2007 | $42.26 | $27.55 | $120.89 | $41.42 |

| | | | | | |
|---|---|---|---|---|---|
| IPL/Alliant | 2007 | $34.80 | $16.55 | $129.64 | $30.44 |
| Black Hills | 2007 | $25.14 | $10.74 | $171.67 | $24.08 |
| **Maine** | | | | | |
| Northern Utilities | 2008 | $55.51 | $24.85 | $165.85 | $30.71 |
| **Colorado** | | | | | |
| Public Service of Colorado | 2009 est. | $36.79 | $15.29 | $33.44 | $39.46 |

Development of DSM Budget

In most jurisdictions covered by our research, gas utilities file with the regulatory agency a DSM plan along with estimated savings targets and a proposed budget. Spending is normally tied to expected energy savings and cost savings. The DSM budget typically includes costs for: 1) planning and design; 2) program delivery; 3) advertising, promotion and customer education; 4) customer incentives/rebates; 5) equipment and installation; 6) evaluation, measurement and verification; and 7) program administration.

In Massachusetts, budgets for the new three-year conservation plans required under the 2008 Green Communities Act are based on the estimated cost of achieving savings goals established by the Energy Efficiency Advisory Council ("EEAC"). The EEAC hired third-party consultants to estimate the reasonable long-term value of energy efficiency and combined heat and power programs. The consultants estimated that for natural gas the long-term value for cost-effective savings is 2% per year. Therefore, LDC conservation budgets were based on the cost of achieving 2% savings per year. Separate from the three year plan budgets, gas utilities in Massachusetts also file an annual Residential Conservation Services budget to support the residential energy audit program.

In Oregon, the Board of Directors approves the budget annually for all existing Energy Trust of Oregon DSM programs. Each program is reviewed individually on an annual basis, at which time the Board may re-establish budget caps for the program depending on its performance. The budget is also, in part, dependent on funding from natural gas utilities. In recent years, funding for ETO has been approximately $10 to $12 million per year for natural gas programs. ETO may not exceed its annual budget, but does have the authority to shift funds from one program to another within the same customer class (i.e., residential, commercial, etc.).

Specified Amounts for DSM programs

DSM budgets in many jurisdictions are based on a certain percentage of annual utility revenue. The following table summarizes how DSM budgets are established in several states that were included in our survey.

**Table 17: States that Establish DSM Budget as Percent of Utility Revenue**

| State | Requirement |
|---|---|
| **Maine** | Energy efficiency programs shall represent no less than 3% of gas utility delivery revenue |
| **Minnesota** | State statute requires utilities to spend 0.5% of gross operating revenue on DSM programs |
| **Oregon** | Utilities are required to contribute approximately 1.0% of gross operating revenues to the Energy Test of Oregon, which is the third party administrator for DSM programs |
| **Wisconsin** | Requires each utility to spend 1.2% of annual operating revenue on DSM programs |
| **Colorado** | Requires gas utilities to spend either 2.0% of base revenues (excluding commodity cost) or 0.5% of total revenues, whichever is greater, on DSM programs |

DSM programs to address different customer classes in the U.S. face several different types of regulatory and budgetary requirements. In Maine, for example, utilities are compelled by statute to commit 20% of their gas conservation budgets to programs that specifically address the needs of small business customers in the state.[75] Maine and Massachusetts are among the states with the most aggressive quantitative requirements for low-income programming. In Maine, gas distribution companies must allocate 10% of conservation funding to programs targeting the needs of low-income customers.[76] Minnesota has also instituted a numeric threshold for low-income programs, requiring its gas utilities to commit a minimum of 0.2% of gross operating revenue. As mentioned above, in Massachusetts, the Energy Efficiency Advisory Council ("EEAC") requires that funds for low-income programs are proportional to the funds that are provided by that sector.

75 Maine Public Utility Commission. Natural Gas Rules, Chapter 480.
76 Maine Public Utility Commission. Natural Gas Rules, Chapter 480.

Cost recovery for DSM programs

Most jurisdictions allow the gas utility to recover the cost of DSM programs through some type of customer charge. California, for example, has authorized a natural gas surcharge of 0.7% of retail sales, which pays for all DSM programs except those targeted at low-income customers. Low-income programs are funded, in part, with proceeds from the Public Purpose Program surcharge. For San Diego Gas and Electric, this low-income surcharge ranges from $0.036 to $0.083 per therm, depending on customer class.[77] Other funding sources, including federal grants and incentives, contribute, as well. In Connecticut, 80% of funding for DSM programs is provided through the Conservation Adjustment Mechanism charge on customer bills, while the remaining 20% is included in the companies' base rates. In Maine, the gas utility recovers costs associated with energy efficiency programs entirely through base rates. Northern Utilities rates are based on projections of its energy efficiency program costs, not actual historic costs, but are reconciled for actual expenditures in the following rate period. New Jersey and New York both provide funding for energy efficiency programs through a system benefit charge assessed on customers by all investor-owned utilities. In Oregon, Cascade Natural Gas is authorized to collect a 0.75% public purpose funding surcharge from its residential and commercial customers to fund DSM programs.

Caps on Spending for Evaluation and Monitoring

Many jurisdictions have placed caps on the amount of the DSM budget which can be spent on evaluating and monitoring DSM program results. Further, the California PUC realized that a small minority of projects make up 80% of total program savings. These programs receive the most extensive review, which is an efficient deployment of EM&V funds; smaller programs are given a less strenuous review.[78] The following table summarizes some of those spending limitations.

[77] Schedule G-PPPS Public Purpose Programs Surcharge. San Diego Gas and Electric, October 31, 2008. http://www.sdge.com/tm2/pdf/GAS_GAS-SCHEDS_G-PPPS.pdf

[78] California Public Utilities Commission, Energy Division, "Energy Efficiency 2006-2007 Verification Report," November 18, 2008, p. 19-24.

**Table 18: Spending Caps on DSM Evaluation and Monitoring**

| Jurisdiction | Spending Cap |
|---|---|
| **California** | 4% cap on utility's EM&V budget (Southern California Gas had requested that 7.5% be set aside for EM&V). |
| **Connecticut** | EM&V budget of 1.4%, but requires significantly more in terms of evaluation. The exact reason for this low EM&V cost is unclear, but may be a combination of factors. Not all programs are evaluated each year, nor are each type of evaluation (impact, process, baseline, market assessments). Also, Connecticut jointly administers gas and electric measures, which may translate to reduced costs.[79] |
| **Maine** | The Efficiency Maine Trust arranges for an independent evaluation of each major program with a budget of more than $500,000 (Northern Utilities' total budget was less than $500,000 in 2008) at least once every 5 years.[80] As a result of this relaxed evaluation standard, the EM&V cost for the state is less than 1% of total budget. |
| **Minnesota** | Cap equal to 10% of first year benefits; allows utilities to keep EM&V costs low by assuming that free ridership is offset by spillover. |
| **New York** | 5% cap on utility's EM&V budget after receiving budget proposals requesting administrative costs that represented 32% to 76% of overall program cost. |

d. Recommendations

Gas distributors were traditionally in the business of selling as much gas as possible to customers. That changed to some extent when energy efficiency and conservation became public policy goals in the 1980s and 1990s. Now, environmental groups and regulators in some jurisdictions believe that energy efficiency and conservation programs should contribute to meeting climate change objectives, while low-income ratepayer advocates contend that energy efficiency and conservation programs should provide affordable rates for low income customers. As noted in Table 4, Ontario's 2007 Action Plan for Climate Change establishes targets for aggressive reductions in greenhouse gas emissions by 2020. In 2007, natural gas accounted for 26% of GHG emissions in Ontario. If gas distributors are to contribute toward a reduction in GHG emissions, then more spending on DSM will almost certainly be necessary. At the same time, there is increased commitment to using renewable energy and natural gas to generate electricity in Ontario. Concentric observes that these changes require gas distributors to continuously re-think how they approach resource planning and how they serve customers. It is important for the Board to implement a DSM framework that

79 State of Connecticut, Connecticut Department of Public Utility Control, "2009 Joint Natural Gas C&LM Plan," p. 75-77).

80 Summary of LD, 1485

provides gas distributors with sufficient funding to develop and deliver energy efficiency programs that meet these policy objectives, while ensuring that the programs are cost effective and do not place undue pressure on customer rates.

In order to achieve more aggressive energy efficiency and conservation targets, Concentric concludes it will be necessary to increase spending on DSM programs in Ontario. As noted earlier in Tables 13 and 14, the average Canadian gas distributor spent approximately 2.0% of utility revenues less the cost of purchased gas on DSM programs in 2007, while the average U.S. gas distributor in our sample spent approximately 3.9% in 2008. Enbridge and Union both spent somewhat more than the average Canadian gas distributor in 2007, at 2.26% and 2.60% respectively. However, these percentages are well below the average spending among the U.S. gas distributors in our sample, and significantly below the gas utilities which spend the highest percentage of utility revenues on DSM – Manitoba Hydro (7.11%), Southern California Gas (5.40%), CenterPoint Minnesota Gas (5.93%) and Cascade Natural Gas (8.21%).

Concentric recommends that the OEB consider establishing a minimum percentage of utility revenues[81] that gas distributors would spend on DSM programs, as well as a range of Board-recommended percentages that encourages gas distributors to pursue innovative or aggressive DSM measures. Concentric recommends a <u>minimum</u> annual budget threshold of 3.0% of utility revenues less the cost of purchased gas, and a <u>Board-recommended</u> range between 4.0% and 6.0%. Some of the relevant parameters for establishing this recommended range might include: 1) achieving a long-term Societal Cost Test equal to 1.0; 2) achieving market penetration of 90% for the Best Available Technologies for mass market DSM measures, and 3) contributing toward achieving any carbon reduction targets that are established as a result of the Green Energy Act or similar future legislation. The following table demonstrates the impact of these recommendations based on 2008 gas distribution revenues for Enbridge and Union. Concentric notes that our recommended minimum threshold of 3.0% would result in spending that is only slighter higher than the 2010 DSM budget approved for Enbridge ($25 million) and slightly below the 2010 DSM budget approved for Union ($22.6 million).

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[81] We use the term "utility revenues" to refer to total operating revenues less the cost of purchased gas. Alternatively, this might be considered as distribution revenues.

**Table 19: Minimum and Recommended DSM Budgets Based on 2008 Distribution Revenues**

| Utility | 2008 distribution revenue[82] (million) | DSM Budget at 3% (million) | DSM Budget at 4% (million) | DSM Budget at 6% (million) |
|---|---|---|---|---|
| **Enbridge** | $1,010.6 | $30.32 | $40.42 | $60.64 |
| **Union** | $675 | $20.25 | $27.00 | $40.50 |

**Table 20: Customer Rate Impact of Minimum and Recommended DSM Budgets**

| Utility | 2008 customers[83] | Annual cost per customer at 3% | Annual cost per customer at 4% | Annual cost per customer at 6% |
|---|---|---|---|---|
| **Enbridge** | 1,865,020 | $16.26 | $21.67 | $32.51 |
| **Union** | 1,309,430 | $15.46 | $20.62 | $30.93 |

Concentric recommends that the Board allow gas distributors some flexibility in proposing budgets to meet the DSM metrics and targets discussed in Issue #7 below. In our opinion, the utilities are in the best position to determine which DSM programs and measures will meet the specific DSM metrics and targets that have been established by the Board because they have more interaction with customers and they understand how customers respond to various programs. Therefore, we believe that the gas distributors, in consultation with interested stakeholders, should submit their budget request to the Board for approval.

Concentric believes that it is reasonable to establish separate DSM budgets for Resource Acquisition Programs, Market Transformation Programs, and Low-Income Customer Programs. However, we do not have sufficient information to evaluate the reasonableness of the percentages that should be allocated to each segment in Ontario. Concentric also endorses the current DSM variance account as an effective method for reconciling the difference between actual DSM spending and budgeted amounts.

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82 Source: Enbridge – 2008 Auditor's Report; Union Gas – 2008 Annual Report

83 Source: Ontario Energy Board, 2008 Yearbook of Natural Gas Distributors, September 10, 2009

Finally, the cost to evaluate and monitor DSM programs can be a significant percentage of the DSM budget. Concentric believes that, while program evaluation and monitoring are important, the primary focus should be on designing, developing and delivering DSM programs and measures that achieve the policy objectives established by the Board. Therefore, Concentric recommends that the Board consider more extensive review of those programs that account for the majority of expenditures and savings, and that smaller programs be subject to less rigorous or less frequent scrutiny. For example, the Board might evaluate the largest DSM programs every year, and smaller programs on a two or three year rotating cycle. Alternatively, the Board may consider a cap on spending for evaluation, monitoring and verification. Based on our research, Concentric recommends that an appropriate range would be 3% to 5% of the total DSM budget for each gas distributor.

## XIV. Issue #7: DSM Metrics and Targets

### a. Existing DSM Framework in Ontario

The DSM metrics and targets in the existing DSM Framework were approved by the Board in its August 26, 2006 decision.

TRC Net Savings Metric and Target

TRC net savings was approved as a single metric with targets for the combined impact of the resource acquisition and the low-income customer programs. Separate metrics and targets were approved for market transformation programs.

The TRC net savings target was established for the first year (2007) of the plan at $188 million for Union and $150 million for Enbridge. For the following two years, the target was to increase based on a formula that averaged each utility's actual audited TRC results over the previous three years and applied to this figure an escalation factor equal to 1.5 times the amount by which the utility's budget was increased. The formula was to be phased in over three years beginning with the 2007 targets as stated above for each utility.

In the event avoided costs used by the utility are later updated, the actual audited results from previous years used to calculate the TRC target must be adjusted to reflect these updated avoided costs.

The following tables present the formula by which DSM targets have been set for Union and Enbridge respectively. Information for 2010 is provided for illustrative purposes only:

**Table 21: Formula to Establish Union's DSM Targets**

| Year | Formula |
|---|---|
| 2007 | $188 million |
| 2008 | The simple average of $188 million and the actual 2007 audited TRC value as approved by the Board increased by 1.5X the budget escalation factor (i.e., 15%) |
| 2009 | The simple average of $188 million and the actual 2007 and 2008 audited TRC values as approved by the Board increased by 1.5X the budget escalation factor (i.e., 15%). |
| 2010 | The simple average of the previous three years actual audited TRC values as approved by the Board increased by 1.5X the budget escalation factor (i.e., 15%). |

**Table 22: Formula to Establish Enbridge's DSM Targets**

| Year | Formula |
|---|---|
| **2007** | $150 million |
| **2008** | The simple average of $150 million and the actual 2007 audited TRC value as approved by the Board increased by 1.5X the budget escalation factor (i.e., 7.5%) |
| **2009** | The simple average of $150 million and the actual 2007 and 2008 audited TRC values as approved by the Board increased by 1.5X the budget escalation factor (i.e., 7.5%). |
| **2010** | The simple average of the previous three years actual audited TRC values as approved by the Board increased by 1.5X the budget escalation factor (i.e., 7.5%). |

The "actual audited TRC value" is the total TRC produced for the year in question as determined by the audit in the following year. In setting the target for 2009 and subsequent years, the actual audited TRC value for the immediately preceding year, but not for the prior two years used in the average, will be adjusted to reflect any changes in input assumptions determined in the audit to apply to that year for purposes of calculating the LRAM. For example, if a free rider rate is increased in the 2009 audit (carried out in the first half of 2010), that change would normally apply to SSM for the years 2010 and thereafter, but to LRAM for 2009 as well. In calculating the target for 2010, the three year average will use the TRC values otherwise determined for 2007 and 2008, but for 2009 will use the audited TRC values, adjusted for that change in the free rider rate identified in the audit.

The formula used to derive the targets in years two and three of the plan is self adjusting to account for actual performance in the previous year. The Board concluded in its August 26, 2006 decision that this formula is preferable to setting the targets for all three years in advance.

When evaluating the success of a distributor in reaching these targets, the distributor's DSM activities are to be 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.

Market Transformation Metrics and Targets

For each market transformation program the utility is required, in its multi-year plan, to propose a program description, goals (including measurement method), incentive (including structure and payment), length, level of funding and program elements. Such programs were not amenable to a formulaic approach and therefore were to be assessed on their own merits and all of the above components were to be suitable given the subject matter and program goals.

The utilities submit an annual Market Transformation Incentive Scorecard to the Board for its approval. The scorecard contains a number of metrics and weights to determine an appropriate incentive for program execution and performance. These metrics relate to market penetration vs. baseline, product sales, indicators of lasting market effects and/or reduction in market barriers, effective and efficient performance of planned activities, and decline in the per unit cost of equipment.

Consistent with the existing DSM Framework, the Draft DSM Guidelines accept 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 the given program. Such metrics should be able to measure success objectively, such as increasing the market share of a DSM technology. Depending on the program, other quantifiable metrics could include an increase in consumer awareness due to an educational program. Distributors are expected to propose specific metrics and corresponding targets for any proposed market transformation program. For each market transformation program, utilities are expected to propose a program description, goals (including measurement method), shareholder financial incentive (including structure and payment) length, level of funding, and program elements.

Low Income Programs

There were no metrics and targets set for low income programs in the existing DSM framework. The Board's Draft DSM Guidelines clarified that TRC net savings targets are to be set for resource acquisition programs, excluding market transformation programs and DSM programs targeted to low-income customers.

According to the Draft DSM Guidelines, low-income customers face certain unique barriers in accessing DSM programs. Further, the TRC net savings for these programs are typically low relative to the savings of other programs even though they are very valuable for this particular market segment. Under the Draft DSM Guidelines, targets for low-income programs would be based in part on TRC net savings, but also in part on other metrics such as market penetration of DSM programs. Distributors would be instructed to develop eligibility criteria and program parameters for low income residential programs. The Draft DSM Guidelines suggest that eligibility criteria presently used by various levels of government may be appropriate for use by distributors. Additionally, distributors would be expected to propose explicit metrics and corresponding targets for the DSM programs targeted at low income consumers.

b. Stakeholder Comments

Stakeholders have expressed concerns that the TRC net savings targets do not appropriately incent utilities to promote DSM technologies and programs with longer-term savings, and that alternative metrics and targets are needed.

Resource Acquisition Metrics and Targets

Ratepayer representatives advocated for replacement of TRC net savings targets with targets for per capita consumption of natural gas specific to classes of customers or specified end users. Representatives of environmental interests, on the other hand, supported the use of the TRC net savings for setting targets with two qualifiers: first, that free ridership is calculated not on the basis of the technology, but based on individual program evaluation results; and second, the TRC net savings are calculated based on the most recent available information from program evaluations. The two utilities object to the use of best available information, finding that adjusting assumptions and free-ridership rates for the assessment of TRC savings is both costly and time-intensive. In addition, the utilities believe that fixed input assumptions facilitate better utility planning and more effective use of DSM budgets. Both Enbridge and Union did not support the existing "complex target setting" approach and proposed following the target setting payout protocol of 5% of total TRC net savings achieved, which is currently applied in the electricity sector.

These stakeholders cited several additional problems with the TRC savings, principally stemming from the "bottom up" estimation of savings and the use of the TRC savings for incentive payments, which drive "the ongoing battles over evaluation and audits of programs."

Market Transformation Metrics and Targets

Representatives of ratepayer interests identified market transformation as an "outdated" concept, mainly due to the many players with programs in the field of energy conservation that make it difficult, if not impossible, to attribute causation. Representatives of environmental interests called for further clarity in terms of metrics measuring market transformation activities with more emphasis on lost opportunity markets rather than education and training activities. Both distributors identified the need for expanded and program-specific metrics for market transformation programs, including the use of the scorecard approach with quantitative and qualitative elements built in.

Low Income Customer Programs Metrics and Targets

Some of the ratepayer representatives requested the replacement of the TRC test with the Low-Income Public Purpose Test, which is similar to the TRC test but also measures benefits such as reduction in costs of arrears managements, late payments, etc. They also emphasize the unique nature of the low-income market in requiring significantly more resources, and for longer periods, than other market segments. They were also supportive of separate budgets and targets for low-income programs. Representatives of environmental interests were consistent with those of ratepayer interests in their support for increased spending on DSM programs targeted to low-income customers and the need for specially tailored budgets, incentives and program offerings. Union and Enbridge also support having separate budgets and targets for low-income programs in order to meet the special needs of low-income consumers and to capture the value of some measures, which are not high in TRC net savings, but are potentially valuable measures for this segment of the market.

Stakeholders involved in the CWG agreed to a set of performance metrics specific to low-income DSM programs.[84] The CWG decided that targets would be set, and performance scored against three distinct measures:

- Number of basic measure participants
- Number of extended measure participants
- Total lifetime gas savings ($m^3$) for extended measure participants only.

There was a suggestion, but no agreement, that there should also be a scored metric for education and training.

[84] Report on the Proposed Short-Term (2010) Framework for Natural Gas Low-Income DSM – Final Report of the Conservation Working Group to the Ontario Energy Board. Prepared by Indeco Strategic Consulting, Inc., August 13, 2009, page 26.

The CWG also decided on a second set of metrics that would be tracked by the utilities, and reported periodically to the Board, but not used to score performance for the purposes of determining an incentive amount:

- Proportion of participants referred to the program by social service agencies
- Increase in the number of communities served by "extended" measures, which have compelling long-term benefits to match the enhanced level of effort and expense to install.
- The number of participants in extended measure programs that are referred from conventional DSM programs

Both Union and Enbridge committed to increase the number of communities receiving low income DSM programs, expand the educational programs that are offered to low-income communities, and to reach out to greater numbers of customers living in private and social-sector residential buildings.

### c. Approach in Other Jurisdictions

Measuring Program Success

Different jurisdictions in our survey use different methods to measure the success of DSM programs, including market penetration levels/customer participation rates, specified targets for reduction in gas demand, maximum potential studies for energy efficiency, and carbon emission reduction targets. The following section summarizes the various approaches.

Market penetration/customer participation: Manitoba, Quebec, Maine

The provinces of Manitoba (Manitoba Hydro) and Quebec (Gaz Metro) both consider market penetration as the most important metric for determining success.[85] As a crown corporation, the profit motive for Manitoba Hydro is not as strong compared to other investor-owned utilities. Nevertheless, conservation is promoted in Manitoba because energy (especially electricity) not consumed in the province can be exported at higher rates. The utility decides what level of conservation it thinks is prudent and achievable, and the Manitoba Public Utilities Board either approves this proposal or requires adjustments. Market penetration is the primary measure used to assess the success of DSM programs; however, for low-income programs the utility compares energy consumption to a pres-established baseline.

85 IndEco, "DSM Best Practices Update," p. 61.

Maine has several long-term conservation goals, including weatherizing 100% of homes and 50% of businesses in the state by 2030, reducing heating fuels consumption by 20% by 2020, and seizing all cost-effective electric and gas energy efficiency opportunities. The utility regulator leaves program implementation and compliance planning to the utilities, but reviews and approves the targets established by each utility to ensure that the state's goals will be met or exceeded.

Targets for reduction in gas demand: BC, Minnesota, Colorado, Oregon, New York

The provincial government in British Columbia has established aggressive goals for DSM by its gas and electric utilities. The Utilities Commission Act, which is the legislative mandate for conservation, stipulates a goal of a 50% reduction in aggregate demand increases by 2020.[86] Under the Act, utilities are required to submit long-term resource plans to the British Columbia Utilities Commission ("BCUC") every two years (the actual period is determined for each utility by the BCUC, but two years appears to be the norm) describing how demand reduction goals will be met. The BCUC is authorized to either approve or deny a utility's plan based on whether it complies with provincial policy, will enable the utility to help meet the province's long term conservation goals, and is in the public interest.

Minnesota statute requires utilities to reduce gross retail energy sales by 1.5% annually, although this figure can be adjusted down to 1% by the utility regulator based on the utility's historical conservation investment experience, customer class makeup, a conservation potential study, or load growth. The overall state goal for gas is to reduce per capita consumption by 15% by 2015. Recognizing that this is an ambitious target, Minnesota regulators have not set goals for particular customer segments, leaving such decisions to the utilities.

Colorado regulators set a goal of reducing annual energy sales by 0.53% in 2009, and by a cumulative 11.5% by 2020. Separate goals are set for each customer class, including business, residential, and low-income customers. While reducing total energy sales is the primary goal, utilities are also encouraged to seek broad customer participation.

86 British Columbia Utilities Commission Act, Section 44.1(4)(c). http://www.bclaws.ca/Recon/document/freeside/--%20U%20--/Utilities%20Commission%20Act%20%20RSBC%201996%20%20c.%20473/00_96473_01.xml#section44.1 (website visited on December 8, 2009).

Oregon sets hard conservation targets. The Energy Trust of Oregon ("ETO") sets the state's annual goals based on past performance and the expected cost of conservation. In 2008-9, the ETO aimed to achieve savings of 1.8 million therms at a levelized cost of no more than $0.60/therm. ($2008 US)

New York's preferred framework is also to establish a statewide long-term goal for gas conservation, and to "require program administrators to propose a suite of programs intended and designed to attain or exceed certain minimum targeted levels of savings. The Commission, in determining which programs to approve, will assign funding to those programs most likely, in its judgment, to achieve the greatest savings in the relevant time period, consistent with [New York state] policies for selection of a balanced portfolio of programs." While the New York PSC has established savings goals, utilities may propose the suite of programs they will use to accomplish their individual obligations.

Maximum potential study: California

California's DSM goals are among the most comprehensive and aggressive. Targets are set by the California PUC based on the findings of a maximum potential study, state policies, and prior program results. Utilities are assigned annual and 10-year goals, both of which are updated every three years. As in Minnesota, in order to give the utilities the most flexibility, the CPUC has not set distinct goals for different customer classes.

Carbon emissions reduction: Great Britain

The British government has established the goal of reducing carbon emissions by 80% by 2050. Targets for DSM carbon reductions are based on the number of customers served by a given utility. Each utility may choose which programs or methods it will use to achieve its obligations, as long as its overall plan is approved by the Office for Gas and Electricity Markets (Ofgem). The formula Ofgem uses to assign an obligation under CERT is a proportional share of the country's total reduction requirement. Metrics for each standard technology or program that may be used to meet these goals are determined by the "Building Research Establishment's Domestic Energy Model." The model is based on data from the English House Condition Survey, and is widely used.[87]

The CERT Order sets a minimum threshold for reductions that must be achieved among customers in 'Priority Groups'. Priority Groups include: individuals that receive certain income related benefits, tax credits (where the income threshold has not been met), or who are at least 70 years old. "The Priority Group obligation is that at least 40 per cent of the supplier's carbon obligation is achieved by actions carried out in the Priority Group."[88]

Who Establishes Metrics and Targets

Another consideration is whether the metrics and targets are established by the regulator or the utility. Among the jurisdictions in our survey that require energy efficiency and conservation programs, seven jurisdictions (six U.S. states and Great Britain) require utilities to deliver DSM programs that meet targets established by regulatory bodies, while five jurisdictions (one Canadian province and four U.S. states) require utilities to propose DSM targets and metrics for review and approval by state regulators. When the regulatory agency establishes DSM targets and metrics, they typically leave specific program details to the gas utilities in order to allow maximum flexibility across customer classes.

Evidence Regarding Reduction in Gas Usage

One way to measure the success of DSM programs is to examine the reduction in gas consumption as a percentage of total gas sales. Although operating information is limited and somewhat difficult to obtain, the following table compares the reported reduction in gas consumption attributable to DSM programs to the total gas consumption for six gas distributors that operate within the states covered by our research survey. The table demonstrates that the most successful companies in our survey were able to achieve a reduction in total gas consumption of approximately 1%. This underscores the difficulty that companies and regulators face in achieving meaningful reductions in natural gas consumption. Concentric does not interpret these results to indicate that DSM programs cannot succeed; however, we do believe that there are significant challenges which must be

[87] Information on BREDEM is provided at the end of the UK discussion in the *Resources* section.
[88] Carbon Emissions Reduction Target (CERT) 2008-2011 Supplier Guidance - Version 2. September 18, 2009.

overcome in order to produce the magnitude of results which many policy-makers and stakeholders are seeking.

**Table 23: Reduction in Gas Consumption as a Percentage of Total Usage, by Customer Class as the result of DSM Programs**

| Utility | State | Customer Class | Savings, as a Percentage of Total Consumption |
|---|---|---|---|
| **PSCo** | Colorado | Residential | 0.25% |
| | | Comm. & Ind. | 0.19% |
| | | Total | 0.23% |
| **IPL/Alliant** | Iowa | Residential | 1.39% |
| | | Non-Residential | 0.70% |
| | | Total | 1.00% |
| **Black Hills** | Iowa | Residential | 1.01% |
| | | Non-Residential | 0.49% |
| | | Total | 0.88% |
| **CenterPoint** | Minnesota | Residential | 0.22% |
| | | Comm. & Ind. | 1.83% |
| | | Total | 0.76% |
| **Northern States Power** | Minnesota | Residential | 0.37% |
| | | Comm. & Ind. | 2.09% |
| | | Total | 1.01% |
| **Cascade Natural Gas** | Washington | Total | 0.16% |

d. Recommendations

One of the most difficult aspects of designing a cost effective energy efficiency and conservation program is determining how to measure success. From our perspective, this concern is best addressed by developing DSM metrics that are straight-forward and verifiable. In our opinion, TRC net savings is difficult to measure and verify, and may have contributed to the development of shallow DSM programs in Ontario (that is, programs with modest energy savings or a short-term focus). Concentric recommends that the Board adopt market penetration of the Best Available Technologies as its primary metric for evaluating whether a particular DSM program or measure is successful. In situations where market penetration is not applicable or cannot be measured (e.g., attic insulation might be difficult to observe), Concentric recommends measuring the reduction in gas consumption per customer attributable to the DSM program or measure.

The market penetration metric would require gas distributors to establish a baseline of the existing circumstances in Ontario for each energy efficiency and conservation measure by conducting an inventory assessment. Once this work is completed, the OEB would be able to measure program success by establishing market penetration targets for each specific energy efficiency measure by a certain date. For example, the Board might determine that it wishes to set a target of 75% market penetration for installation of the best available replacement windows by 2020, or a 60% market penetration for installation of the most efficient gas furnaces by 2025. These percentages would depend on several factors, including the results of the inventory assessment that establishes the baseline for each measure, any specific metrics the Board may set regarding reductions in per capita gas consumption, and any carbon emission reduction targets that may be promulgated as a result of the Green Energy Act. Concentric recommends that the Board consider establishing long-term market penetration targets that cover three to five years, and require the gas distributors to propose how to achieve these targets in their DSM plan filings.

Concentric believes that using market penetration as the primary DSM metric has several important advantages. First, market penetration is a much more objective and measurable standard than energy savings. Second, it would mitigate the concern surrounding the financial incentive payment to gas distributors because there would be less concern among stakeholders that the utilities were being rewarded for achieving nebulous DSM results that could not be measured and independently verified. However, we recognize that market penetration does not resolve the ongoing controversy surrounding free ridership.

Concentric recommends that the Board strongly encourage gas distributors to focus on DSM programs which have the highest potential for increasing market penetration of BAT. By concentrating on market penetration, Concentric believes the Board can more accurately measure and evaluate the success of DSM programs. Once it has been determined that end-use applications are in the public interest, it is more straightforward to monitor penetration of those applications. This approach will result in the selection of DSM programs that maximize the economic potential of energy efficiency and conservation programs, rather than simply passing a minimum benefit/cost threshold of 1.0.

Finally, Concentric believe that similar metrics could be developed for it DSM programs serving low-income customers. Market penetration and the reduction in gas consumption per customer appear to be equally appropriate for this customer segment. However, the targets might be different for certain programs and measures. For example, the Board may want to establish a higher market penetration standard (perhaps 90%) for home weatherization of low-income properties to ensure that energy savings is maximized.

## XV. Issue #8: Shareholder Incentive Mechanism

### a. Existing DSM Framework in Ontario

In its August 2006 decision in EB-2006-0021, the Board determined that a Shared Savings Mechanism ("SSM") was to be established for the first year of the plan, to be in effect for each year of each multi-year plan. The SSM was indexed to the TRC net savings targets developed for each utility as discussed under Section XV above.

The cumulative SSM payment to each utility for achieving their respective TRC target was set by a formula. For purposes of determining whether each utility has met its 100% TRC target, the input assumptions for the calculation of SSM were not to be changed retroactively. For clarity, it was determined that changes to input assumptions, which are confirmed through audit, apply in the year immediately following the year being audited. For example, any changes to input assumptions resulting from an audit of the 2007 DSM results (which is undertaken in early/mid-2008) would apply from the beginning of 2008, not 2007. In other words, for purposes of the SSM calculation, input assumptions used in the calculation of TRC savings are considered to be "locked-in" from the prior year.

The SSM is calculated according to a formula with escalating percentage thresholds starting at the first dollar of TRC net benefits achieved. The SSM is calculated based on the results as they apply along a curve. Each of the following percentage thresholds serve to structure the SSM curve based on targets and SSM amounts, but do not represent lump sum payments for reaching the specified threshold:

Up to 25% of the annual target, a total payout of $225,000
Up to 50% of the annual target, a total payout of $675,000
Up to 75% of the annual target, a total payout of $2,250,000
Up to 100% of the annual target, a total payout of $4,750,000
Up to 125% of the annual target, a total payout of $7,250,000
In excess of 125% of the annual target, a total that is capped at no more than $8,500,000

The annual SSM cap of $8.5 million is adjusted each October by the Ontario Consumer Price Index ("CPI").

Under the Board's existing DSM Framework each utility is also entitled to an incentive payment of up to $0.5 million in each year of the multi-year plan based on the measured success of market transformation programs. The market transformation programs were seen as not amenable to a formulaic approach and are assessed on their own merits. The measurement and calculation methodologies to determine whether this amount has been earned in the year were to be detailed by each utility in its multi-year DSM plan.

This amount is in addition to any amount earned for meeting the TRC net savings targets. For example, a gas distributor may propose in its DSM plan a program to increase the market share of a particular high efficiency product, and a $250,000 annual incentive based on the market share of that product at the end of each year, measured by a specific third party market index, being 10% higher than the previous year. If the DSM plan has been approved by the Board including that program, the gas distributor will be entitled to a $250,000 incentive in each year that it meets the stated market share goal.

Under the existing DSM framework, there were no separate shareholder incentives approved for low-income customer programs.

The Draft DSM Guidelines indicate that shareholder incentives are an appropriate way to encourage utilities to pursue DSM programs. The Draft DSM Guidelines propose that distributors be allowed to apply for separate incentives for three different types of DSM programs: 1) Resource Acquisition Programs; 2) Market Transformation Programs; and 3) Low Income Programs.

The Draft DSM Guidelines, however, propose certain changes to the TRC net savings calculations for establishing the amount of incentive to be paid. Distributors would calculate the TRC net benefits of the DSM programs, adjusted for free ridership and spillover effects.

For purposes of determining whether a distributor has met its TRC target, the input assumptions for the calculation of TRC net savings would be based on the best available information at the time of evaluation, similar to the LRAM adjustments. The rationale was that 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 prior year in the calculation of TRC savings for SSM purposes (as it is done under the existing DSM framework). By way of example, if in June of 2009 the evaluation or audit of the 2008 DSM programs demonstrates a change in input assumptions, that change shall apply for SSM purposes from the beginning of 2008 onwards until changed again.

Regarding the spillover effect, the Draft DSM Guidelines propose that a distributor that wishes the Board to consider spillover would need to provide comprehensive and convincing evidence that clearly quantifies the effect that spillover has had on program savings and the distributor's revenue.

The Draft DSM Guidelines propose the reward structure for the SSM to continue to be the non-linear function relative to TRC net savings as under the existing framework. Similarly, distributors would be 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. DSM shareholder incentive amounts would be allocated to the rate classes in proportion to the net TRC benefits attributable to the respective rate classes.

The Draft DSM Guidelines also propose that incentive payments for low-income customer programs could be made on an individual program basis. Distributors would be expected to use the program's approved evaluation metrics to determine the program's success relative to the established targets. The incentive payment would be tied to the ability of the program to meet or surpass its established targets.

Similar to the existing DSM Framework, the Draft DSM Guidelines propose an SSM variance account to record the amount of the shareholder incentive earned by the distributor as a result of DSM programs. The balance of this account, together with carrying charges, would be disposed of annually. Distributors would apply for SSM and other financial incentives annually. The payout is calculated according to the non-linear formula described above, and is capped at $8.5 million for both Enbridge and Union.

b. Stakeholder Comments

Representatives of ratepayers and environmental interests supported the use of best available information instead of forecasts and locked-in prior year assumptions in the calculation of the SSM.

Conversely, the utilities believe that updating the input assumptions after DSM programs have been assigned explicit targets places the utilities at a distinct disadvantage.

Ratepayer groups also supported continuing use of a non-linear reward curve for calculation of SSM relative to the TRC net savings. The representatives of environmental interests, however, suggested removing the cap on SSM incentives, and establishing a threshold level for the commencement of shareholder rewards at 75% of the TRC target. Union and Enbridge supported use of the existing SSM calculation. However, Union believes that a non-linear "reward structure" remains adequate, as long as there is no cap to SSM benefits that may accrue to the utilities. The company views the cap as "an artificial barrier to maximizing DSM results." Enbridge, however, believes that utilities should be permitted to propose both linear and non-linear structures.

Certain stakeholders have requested an examination of the processes used to develop, review, approve and update input assumptions for planning purposes and for default values for calculation of SSM. There is considerable debate among stakeholders regarding whether input assumptions should be updated to reflect the most recent results from program evaluations. In particular, one gas utility does not agree that input assumptions should be revised such that utility performance for purposes of the financial incentive calculation (i.e., the Shared Savings Mechanism) is based upon revised input assumptions as opposed to those used from the beginning of the year under review. That same utility endorses adopting a deadline for submitting new material for the purpose of updating inputs and assumptions during the course of a DSM study period, and states that DSM targets should reflect any update in inputs and assumptions that will also be used for the purposes of calculating the actual TRC value created by utility programs.

Certain stakeholders have questioned the methodology used and the shareholder incentive levels corresponding to different calculated TRC net savings. Certain ratepayer interests contend that the incentives offered for DSM are not consistent with the results achieved. Other consumer advocates argue that incentives are entirely unnecessary, and that "facilitating DSM should be a service that the LDCs provide for their customers" because the utilities are kept whole through the LRAM.

Finally, certain stakeholders argue that SSM incentives should be tied more closely to results of low-income DSM programs. Several ratepayer groups suggested that incentives for low income and market transformation programs should be calculated separately from those of conventional DSM programs. Others stakeholders, however, believe that low-income programs should not be evaluated differently.

c. Approach in Other Jurisdictions

Of the five Canadian jurisdictions reviewed in our research, only British Columbia offers incentives to utilities that achieve targets for gas DSM. Of the twelve U.S. states included in our research, eight offer incentives for exceptional program performance. Of the three countries outside North America included in this study, none provide similar financial incentives.

Method for Determining Financial Incentives

In British Columbia, public utility DSM plans may include incentive mechanisms with approval from the British Columbia Utilities Commission. These plans are reviewed annually by the Commission. Until recently, Terasen's DSM plan contained an incentive mechanism that operated in discrete steps. The plan defined threshold levels of demand reduction that provided increasing incentives, beginning at 3% of net TRC benefits, rising to a maximum of 5%. However, in Terasen's most recent DSM proceeding, the explicit structure of the incentive mechanism was removed.

There are two main forms of performance incentives among the eight U.S. states that currently provide such benefits. California, Connecticut, Minnesota, New Jersey, and New York utilize a reward structure based on discrete steps, similar to that in place for Terasen in British Columbia. Colorado and Massachusetts employ calculations involving a variety of factors to arrive at incentive reward levels. Colorado's method uses both the percentage of the savings target that was achieved, and the magnitude of actual energy savings. Massachusetts applies a calculation based on three factors: net total resource benefits compared to the target; plan expenses (with a focus on administrative efficiency); and $CO_2$ reductions compared to target levels.

Magnitude of Financial Incentives

The magnitude of financial incentives (and penalties) varies from state to state, as demonstrated in the following table:

**Table 24: DSM Financial Incentives/Penalties in Select Jurisdictions**

| State | Financial Incentive |
|---|---|
| **California** | Utilities can receive up to 12% of excess TRC benefits; utilities are penalized if performance falls below a certain threshold, which is well below 100% of the target level |
| **Colorado** | Awards a maximum of 20% of net economic benefits or 25% of program expenditures, whichever is lower. The bonus is amount is the percentage of net economic benefits resulting from the DSM plan, and includes an Energy factor (percentage of energy target achieved) and a Savings factor (actual savings achieved divided by approved savings targets). |
| **Minnesota** | If a utility achieve 150% of its initial TRC target, it is eligible to receive approximately 30% of its conservation budget as an incentive |
| **New Jersey** | Has established a dollar cap of $376,620 on performance incentives for commercial and industrial efficiency programs, and $62,802 on incentives for residential gas efficiency programs. Both programs are operated by a third-party administrator, and the residential program administrator notes the significant reduction in performance incentives funds available in 2009. |
| **New York** | Reward structure provides a maximum of $13 million, applied at $3.00 per incremental Mcf of gas conserved; utilities are penalized if performance falls below a certain threshold, which is well below 100% of the target level. |
| **Washington** | Does not reward utilities for achieving program goals, but does assess penalties for poor performance |
| **Great Britain** | Does not provide incentives to utilities that meet or exceed conservation levels established by Ofgem for CERT and CESP programs. However, under both CERT and CESP, Ofgem is authorized to impose penalties on utilities that fail to comply with provisions of the programs.<br><br>Under CESP, bonus credits toward meeting low-income program goals are offered when utilities deliver particular combinations of measures (e.g., providing multiple kinds of energy saving services to individual residential buildings, or serving a minimum number of buildings in a given area). However, these incentives for participation are not, strictly speaking, shareholder incentives in the sense contemplated for Ontario's DSM framework. |

Very limited information is available concerning the financial incentives earned by gas distributors in the jurisdictions covered by our research. It is difficult to draw meaningful conclusions regarding the incentive payments due to differences in program goals, utility size, DSM budgets, and methods for calculating the incentives. However, with those caveats, the following table presents recent financial incentive payments for selected gas distributors in the U.S.

**Table 25: DSM Incentive Payments for Selected Gas Distributors**

| Utility | State | Year | Amount | Customers | $/Customer |
|---|---|---|---|---|---|
| **Xcel Energy** | MN | 2007 | $1.69 million | 469,632 | $3.60 |
| **Pacific Gas & Electric** | CA | 2008 | $33.4 million | 4,269,165 | $7.82 |
| **San Diego Gas & Electric** | CA | 2008 | $300,000 | 3,100,000 | $0.10 |
| **Southern Cal Gas** | CA | 2008 | $2.1 million | 3,400,000 | $0.62 |

Assumptions: Locked-in or Best Available Information

The magnitude of financial incentive mechanisms is often sensitive to changes in the input assumptions that are used to develop DSM targets at the outset of a program period. Different jurisdictions that offer utility incentives handle this issue in a variety of ways.

The British Columbia Utilities Commission requires the use of the best available information whenever possible. However, because DSM program administrative budgets are often extremely limited, it is not always feasible to require utilities to conduct rigorous studies to ensure that assumptions used to calculate incentives are current. Recognizing that this is the case, in certain limited circumstances, the BCUC does not require the use of best available information for program evaluation.

In three U.S. states (Minnesota, Connecticut, and Colorado), input assumptions are established at the beginning of each DSM program period. This single set of assumptions is used both to set conservation program targets, and to calculate shared economic benefits at the close of the program period. Ongoing monitoring and verification assessments by utilities often result in updated input assumptions, but these are only used to establish new benchmarks for future program periods.

In New York, gas distributors began implementing energy efficiency programs required under the Energy Efficiency Portfolio Standard (EEPS) in 2009. The NY Department of Public Service (DPS) has developed and employs a Technical Manual to standardize the measure and program savings estimation approaches used by gas utilities. Lacking verified program savings, the input assumptions in the first iteration of the Technical Manual are based largely on the best information available from programs in other jurisdictions. Guidelines have been developed dictating how these programs will be evaluated and, once underway, the results of these evaluations will be used to update the input assumptions in the Technical Manual as necessary. A sub-committee to the Evaluation Advisory Group (EAG), formed as part of the EEPS framework, has been dedicated to ensuring the input assumptions in the Technical Manual are based on the best available information. Any amendments to the Technical Manual, as proposed by the EAG Sub-Committee, will require a regulatory order by the DPS. The regularity with which such updates to the Technical Manual will be pursued, as well as the effects such updates will have on the recovery of lost revenue and performance incentives remain to be determined.

California created an "open source" database – available to all utilities, stakeholders and the public – to house the input assumptions for most energy efficiency programs. It was originally thought that, whenever new information became available, the assumptions would be updated. The problem with this was realized when the Commission began evaluating the utilities' reported achievements. All the Commission's findings, which were based on the most current *ex post* input assumptions, were much lower than what the utilities had been claiming, which were based on assumptions that were accurate at the time of implementation. In particular, one update that seemed to consistently penalize the utilities was a spillover adjustment made to account for the interactive effects of compact fluorescent lights.

Initially, it was reasoned that incentives should ultimately be based on *ex post* findings, as these are the most credible. "Tying compensation to the verified savings will better align the administrators' incentives with the Commission's goals."[89] Over the course of the program cycle (three years), three claims would be made for incentive payments, one each year. The first two claims would be evaluated using *ex ante* assumptions of energy savings and demand reductions, which would be locked annually, in conjunction with verified installations and verified costs. Thirty-five (35%) of the calculated incentive would be held back until the final claim was processed. Although *ex ante* assumptions would be locked for the year, administrators were encouraged to use a more realistic assumption if an existing assumption was clearly high, as the utility will be rewarded based on *ex post* findings in the end. The final claim would be based on a "true-up" of assumptions based on *ex post*

[89] California Public Utility Commission, Decision 05-04-051, April 21, 2005.

findings.[90] In the end, however, it was determined that these updates constituted too much of a "moving target" and, in the most recent DSM budget approval, the Commission committed to locking in the 2008 DEER *ex ante* values for the purpose of evaluating the 2009-2011 program cycle.[91]

d. Recommendations

The financial incentive mechanism should reward gas distributors for achieving various DSM program objectives, including market penetration of energy efficient appliances, cost effective energy savings, implementing market transformation programs that influence consumer behavior, and serving low income customers. Concentric believes there is merit in expanding the ways by which a gas distributor in Ontario can earn financial incentives. This approach is consistent with NRRI's observation that utilities need adequate financial incentives so that they will design DSM programs that encourage customer participation. However, with higher potential incentive payments comes the desire from stakeholders and the Board itself for more verifiable results. An important advantage of adopting market penetration as the primary standard by which to measure program success is that it is relatively simple to independently verify whether the utility has achieved the target market penetration ratio for different DSM technologies. Therefore, Concentric recommends that the financial incentive mechanism be primarily tied to the success of the gas distributor in achieving pre-determined market penetration levels for each DSM technology. Further, Concentric recommends that the Board set metrics and targets for gas distributors so that they are incented to pursue DSM measures that provide deep energy savings.

The financial incentive mechanism should be designed to encourage gas distributors to pursue aggressive targets that result in significant progress toward market penetration of the Best Available Technologies and meaningful reductions in gas consumption per customer. The current incentive structure does not appear to provide sufficient impetus for utilities to go beyond the generic solutions to energy efficiency. Concentric recommends that the Board develop an incentive formula that considers the magnitude by which the gas distributor exceeds certain metrics or targets,

90 California Public Utility Commission, R.06-04-010, "Energy Efficiency Policy Manual, Version 4.0," August 2008.

91 California Public Utility Commission, A.08-07-021 "Decision Approving 2010 to 2012 Energy Efficiency Portfolios and Budgets," July 21, 2008.

including market penetration, reduction in gas consumption, and/or contributions toward reductions in carbon emissions.

Concentric recommends that gas distributors should not be eligible to receive financial incentive payments if they do not exceed the established DSM metrics and targets for each program (i.e., resource acquisition, market transformation, and low income), whether it be for market penetration, energy savings, or carbon emission reductions. Concentric does not believe that gas distributors should be rewarded for achieving less than 100% of program success. Conversely, we do not believe that penalties for failing to achieve 100% success are advisable.

For low income programs, Concentric recommends that the Board develop a separate financial incentive mechanism that is contingent on market penetration, reductions in gas consumption, and efforts to reduce customer bills through education and awareness programs for low income consumers.

As noted under Issue #3, the Board-approved input assumptions are updated annually based on the results of the evaluation report. When input assumptions are updated, Concentric believes that it is appropriate to use best available information for purposes of calculating the financial incentive payment. Our recommendation is based on the premise that the Board-approved input assumptions have been developed with the assistance of an expert consultant, that stakeholders have had ample opportunity to comment on those input assumptions, and that any changes for existing DSM measures will tend to be refinements. If Ontario did not already have significant experience with its DSM program, we would be more sympathetic to arguments regarding the value of "locked-in" input assumptions, so that year-to-year changes in input assumptions should be more modest.

## XVI. ISSUE #9: LOST REVENUE ADJUSTMENT MECHANISM (LRAM)

### a. Existing DSM Framework in Ontario

The Board's existing DSM Framework established a Lost Revenue Adjustment Mechanism ("LRAM"), which is a retrospective adjustment designed to allow gas distributors to recover revenues lost from distributor-supported DSM activities in the prior year. Since the primary purpose of DSM activities has been to reduce natural gas consumption, it also has the effect of reducing throughput and associated distributor revenues, which can act as a disincentive for utilities to develop and deliver DSM programs. 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 else being equal. The LRAM is designed to compensate a distributor only for the unforecasted lost revenues associated with DSM activities undertaken by the distributor within its franchise area.

Under the existing DSM framework, 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 rate class. The assumptions and savings estimates used in the calculation are those in the approved DSM plan, adjusted for the audit Evaluation Report results. These assumptions apply from the beginning of the year being audited. LRAM amounts are adjusted for free riders and for spillover effects to the extent those can be empirically estimated. For example, if in June 2008, the audit of the 2007 DSM programs demonstrates a change in input assumptions, that change will apply for LRAM purposes from the beginning of 2007 onwards until changed again.

For Union, the first year impact of programs was calculated as 50% of the annual volumetric impact, multiplied by the distribution rate for each of the rate classes in which the volumetric variance occurred. For Enbridge, the first year impact of programs was calculated on a monthly basis, based on the volumetric impact of the measures implemented in that month, multiplied by the distribution rate for each of the rate classes in which the volumetric variance occurred. The reason for the difference is that Union does not track when during the year a DSM program was implemented, and therefore the adjustment is intended to account for the fact that programs implemented later in the year do not result in a full year's worth of lost revenues.

The Board has also established an LRAM variance account which records the amount of distribution margin gained or lost when the distributor's DSM programs are less or more successful than budgeted. An application to clear the balance in the LRAM variance account, together with carrying charges, is made on an annual basis. The LRAM account is cleared annually.

Lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board. LRAM is 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.

The Draft DSM Guidelines do not propose any changes to the LRAM. However, the OEB is currently reviewing alternative approaches to revenue adjustment and cost recovery mechanisms, including revenue decoupling for electricity and gas distributors in a separate study.

b. Stakeholder Comments

Certain stakeholders have expressed concerns regarding perceived weaknesses in the LRAM calculation process, which they believe may result in utility recovery of inappropriate amounts. Specifically, they believe it is imperative that LRAM calculations be based on the best available information at the time adjustments are to be applied (as under the existing DSM framework).

Certain stakeholders have requested an examination of the processes used to develop, review, approve and update input assumptions for planning purposes and for default values for calculation of LRAM. By and large, stakeholders are consistent in their support for the use of best available information in the calculation of LRAM.

Enbridge agrees that assumptions should be the best available at the time of an audit, but it proposes that the Board establish a date by which information used to inform LRAM calculations must be submitted. Enbridge feels that otherwise the company and ratepayers would essentially be penalized during unnecessary delays. Union, on the other hand, supports the approach to LRAM described in the Draft DSM Guidelines.

One environmental stakeholder argued that the initial year of Enbridge's LRAM calculation is too expensive and complex to audit, and suggested a calculation methodology in which the LRAM volume is equal to half of the "annual fully effective savings volume."

c. Approach in Other Jurisdictions

Eight of the 16 jurisdictions reviewed in our research allow natural gas utilities to recover lost revenue associated with energy efficiency and conservation programs. In Canada, ratepayer-funded natural gas conservation programs are not as prevalent as in the U.S.; however, where ratepayer-funded conservation programs do exist (i.e., Ontario and British Columbia), utilities are typically allowed to recover lost margin resulting from such programs. In the U.S., lost margin recovery is already the norm for natural gas utilities. Of the 34 U.S. states that offer natural gas conservation programs, 19 currently allow utilities to recover lost revenue and several others have initiated pilot lost revenue mechanisms or have regulation pending.[92]

The mechanisms employed by gas distributors to recover lost margin associated with conservation programs commonly fall into one of two general categories: Lost revenue adjustment mechanisms and revenue decoupling mechanisms.

With a LRAM (sometimes referred to as a margin tracker) lost revenue resulting from utility-sponsored conservation measures can be tracked and applied as a surcharge to customer rates. The revenue lost as a result of conservation programs is calculated, tracked in a deferral account, and then amortized and recovered over time via additional customer charges. Four of the eight jurisdictions (i.e., British Columbia, Connecticut, Massachusetts, and New York) have implemented LRAMs in order to allow utilities to recover lost margin. As a method for utilities to recover lost revenue, LRAMs are somewhat controversial in that to accurately calculate the lost margin from conservation programs, program-specific reductions in customer usage must be distinguishable from other causes of reduced consumption. This is a difficult distinction to make meaning that the calculation of lost revenue involves a good deal of uncertainty and can result in unwarranted customer charges.

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92 American Gas Association, "Regulatory Approaches to Promoting Energy Efficiency", May 2009.

Non-traditional rate designs sever the link between utility revenue and the volume of customer gas usage thus removing a major disincentive for utilities to offer conservation programs. The most common cost recovery mechanism, revenue decoupling, uses a "true-up" charge to adjust distribution service revenue after energy usage has been metered. By allowing utilities to recover margin costs independent of customer energy usage, non-traditional rate mechanisms ensure that natural gas conservation measures do not result in lost utility revenue. Five of the eight jurisdictions offering lost margin recovery—California, New Jersey, New York, Oregon, and Washington—have accomplished this by implementing revenue decoupling.

In two jurisdictions—Connecticut and New York—utilities may implement either an LRAM or revenue decoupling. In 2007, Connecticut ordered the state's electric and natural gas utilities to decouple distribution revenues from the volume of natural gas or electricity sales through one or more of three strategies: (1) a mechanism that adjusts actual distribution revenues to equal allowed distribution revenues (i.e., revenue decoupling); (2) rate design changes that increase the amount of revenue recovered through fixed distribution charges (i.e., straight fixed-variable rate design); and/or (3) a sales adjustment clause (i.e., lost revenue adjustment mechanism).[93] To date, none of the natural gas utilities in Connecticut has implemented revenue decoupling, relying instead on LRAMs. In New York, National Grid has an LRAM in place, while Consolidated Edison and National Fuel Gas Distribution have both implemented revenue decoupling.[94]

Some states with an LRAM already in place are now also implementing revenue decoupling. Massachusetts utilities currently recover lost revenue resulting from conservation programs through a conservation charge included in each utility's local distribution adjustment clause.[95] However, in 2008, Massachusetts announced that it will require all natural gas and electric utilities to include a revenue decoupling proposal in their next rate case. The Massachusetts Department of Public Utilities expects all of the state's natural gas utilities to have implemented revenue decoupling by 2012. Revenue decoupling is expected to eliminate the loss of revenue associated with utility-sponsored conservation programs.

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93 American Council for An Energy Efficient Economy (ACEEE) website, http://www.aceee.org/.
94 American Gas Association, "Regulatory Approaches to Promoting Energy Efficiency", May 2009.
95 2010-2012 Massachusetts Joint State-wide Three-Year Gas Energy Efficiency Plan, July 2009.

Finally, our research indicates that jurisdictions are consistent in their treatment of input assumptions for purposes of determining the lost revenue adjustment mechanism and the financial incentive paid to utilities. That is, jurisdictions which lock-in the input assumptions do so for both the LRAM and the financial incentive calculation, while jurisdictions which use best available information for the input assumptions apply this approach to both the LRAM and the financial incentive calculations.

d. Recommendations

From our perspective, energy efficiency and conservation programs cannot succeed unless the program is revenue neutral for the regulated utility. NRRI has noted the importance of developing a DSM policy framework that harmonizes a utility's financial motivations with energy efficiency initiatives, so that a utility does not suffer lost revenues as a result of complying with regulatory objectives. Concentric's research indicates that other jurisdictions are moving away from LRAMs (where the utility is only recovering lost revenues that are specifically attributable to energy efficiency and conservation programs) toward revenue decoupling (where the utility recovers lost revenues regardless of the reason). In 2005, the National Association of Regulatory Utility Commissioners ("NARUC") passed a resolution advising state commissions to consider the implementation of revenue decoupling. The resolution stated that revenue decoupling mechanisms "may assist, especially in the short term, in promoting energy efficiency and energy conservation and slowing the rate of demand growth of natural gas."[96]

Concentric recommends that the Board consider providing gas distributors with the opportunity to request revenue decoupling.[97] This sends the signal that regulators recognize the risks associated with cost recovery due to declining average use per customer, and are willing to provide utilities with the opportunity to recover all reasonable and prudent costs regardless of customer usage. Allowing gas distributors revenue stability through revenue decoupling removes any financial disincentive to propose energy efficiency programs that might result in significant reductions in consumption. However, some utilities may be reluctant to request revenue decoupling due to concerns that it

[96] See NARUC, "Resolution of Energy Efficiency and Rate Design," adopted November 16, 2005.
[97] Concentric is aware that the Board has retained Pacific Economics Group to study the potential for alternative cost recovery mechanisms such as revenue decoupling.

removes their incentive to add new customers, and that regulators might be under pressure to keep rates low by reducing the authorized rate of return.

Concentric's recommendation is designed only to deal with the issue of lost revenues attributable to energy efficiency and conservation programs; it is not intended to address other issues such as weather normalization, economic conditions or other factors which is beyond the scope of this report. As noted above, the Board is currently studying alternative cost recovery mechanisms more generally in another study entitled *Review of Distribution Revenue Decoupling Mechanisms*.

If revenue decoupling is not adopted by the Board, or until such time as it is implemented, Concentric believes that the necessary information is available to calculate the LRAM based on energy savings (which is contained within the Societal Cost test and Program Administrator Cost test) and market penetration (which is the primary metric we recommend for measuring program success). Further, if the Board continues to rely on the LRAM, Concentric recommends that the calculation should be based on updated input assumptions. However, we agree with Enbridge that it is reasonable to establish a date by which information used to calculate LRAM must be submitted.

## XVII. ISSUE #10: DSM CONSERVATION IMPACT EVALUATION

### a. Existing DSM Framework in Ontario

Enbridge and Union are accountable to the Board to develop and implement cost effective DSM programs including the monitoring and evaluation of program results. In order to inform stakeholders and the Board on the activities and results of DSM programs undertaken, the utilities are required to file annually a clear and concise Evaluation Report that summarizes the savings achieved, budget spent and evaluations conducted in support of those numbers.

The purpose of the evaluation and audit process is to review all input assumptions related to the delivery of DSM programs over the period of the multi-year plan. To assist with that purpose, the Board's existing DSM Framework established an Evaluation and Audit Committee ("EAC") to engage stakeholders in the development of an evaluation plan and budget and in a review of the evaluation results as they become available over the term of the plan.

The Draft DSM Guidelines do not propose any changes to the EAC. It provides, however, more detailed guidance regarding how to evaluate different types of programs including direct acquisition programs, market support programs, customer projects, market transformation programs and low income programs. It also provides guidance on the content of the evaluation plans and the undertaking of independent third party audits.

### b. Stakeholder Comments

Certain stakeholders proposed improving or replacing the existing process used to evaluate the impacts of DSM programs. According to these stakeholders, key disadvantages of the current process include the significant amount of time, effort and cost associated with calculating and agreeing upon the impacts of a wide variety of DSM programs. An environmental advocate has suggested that the existing impact evaluation method be largely replaced with one that evaluates the use of gas by the average customer over time. The organization believes that utility incentives can be problematic and "could be clarified in a framework based on normalized reduction in average usage." Another environmental interest recommended that regardless of the protocol, a rigorous and comprehensive evaluation plan that can provide a sense of a project's success "should be a prerequisite for program funding."

From the ratepayers' perspective, many of the problems with the evaluation and audit process can be traced back to the assumptions-driven TRC test. There was also doubt expressed as to the degree of independence of auditors employed by the distributors. Citing conflict of interest concerns and practice in other jurisdictions, representatives of environmental interests suggested that gas distributors should not be responsible for the appointment of a third party for the evaluation of programs and the setting of the scope and terms of engagement for DSM evaluation work. They called for the Board to select and hire a third party to evaluate and audit both gas distributors. Under this model, the distributors would pay for the work and have input to the process. Union and Enbridge, however, value independent third party evaluation and want to maintain responsibility for verification of program results, costs, etc. They object to the negotiations involving the Evaluation and Audit Committee once the third party review is complete.

Enbridge also suggests that the Board consider implementing a more qualitative assessment methodology, which will provide the utilities with adequate flexibility to propose methodologies that are designed to evaluate the results of programs with different design elements. Union is concerned that "adding the evaluation, measurement and verification costs into the program level TRC would unfairly disqualify many programs, especially given the new, more onerous evaluation requirements by program."

c. Approach in Other Jurisdictions

Our review of other jurisdictions indicates that utilities are generally required to report similar information to regulators, regardless of jurisdiction, including the following: 1) budget versus actual expenditures; 2) projected versus actual savings; 3) customer participation rates; and 4) cost-effectiveness ratios (or levelized cost per therm). This data allows the regulator and interested stakeholders to evaluate DSM program effectiveness as well as progress toward energy savings goals, and the accuracy of utility projections.

<u>Methods to Evaluate and Monitor DSM Programs</u>

Regulators use a variety of different techniques to evaluate and monitor DSM programs, including: 1) audits (to ensure models and calculations are correct); 2) inspections (to ensure that measures were indeed installed); and 3) evaluations (to update the validity of assumptions). Utilities in Quebec, Manitoba and Saskatchewan all conduct "internal" independent reviews of reports, calculations and DSM program administration, relying on other departments, such as accounting.[98] Gaz Metro conducts its audits annually, while Manitoba Hydro and SaskEnergy perform reviews less frequently. Evaluations, which cover the program results and input assumptions, are typically reviewed annually in Canada; however, Gaz Metro evaluates each program once every three years, on a rotating basis, and only if the program covers enough participants to justify it. Oregon uses field inspections to "true up" reported results on an annual basis. Connecticut's ECMB enlists third parties to conduct impact, process, and baseline evaluations along with market assessments. The impact, process, and baseline evaluations encompass the audit, inspection and evaluation functions mentioned.

California employs all three of these checks (i.e., audits, inspections and evaluations). As with other aspects of DSM policy, California has been an innovator in the area of measuring and verifying gas energy savings. Believing that measurement is critical for fostering improvement, the California PUC pursued and created a rigorous evaluation methodology with the help of utilities, stakeholders and other interested parties. Six sources are used to check reported savings:

1) Program Tracking Data (from the utilities)
2) E3 Calculators (which calculate savings based on inputs)
3) Database for Energy Efficiency Resources (a centralized database of savings assumptions)
4) Utility Work Papers (calculations and assumptions for project savings from utilities)
5) Hardcopy Project Files (paper records of more complex EE programs)
6) Installation Rates from EM&V Contractor Verification Reports (independent surveys)

Program tracking data provided by utilities shows raw information about the programs and number of units implemented. The E3 Spreadsheets are standard spreadsheets updated by the utility with information it has collected that calculate demand reduction, avoided costs, and cost effectiveness. The Database for Energy Resources (DEER) is a centralized database which contains input assumptions for unit savings, effective useful life and net-to-gross adjustments. These common assumptions are updated based on recent evaluation studies, utility workpapers, building simulation software and engineering algorithms, and are shared by utilities to standardize the process. The E3

98 IndEco, "DSM Best Practices Update," p. 71.

Calculators and DEER database are available to the public. Any custom measures utilized by the utilities are explained in workpapers submitted to the California PUC. Hardcopy project files are also submitted, which provide useful information for planning audits and field inspections. Finally, on-site inspections and surveys are conducted by independent contractors as part of a "rigorous measurement and verification of the reported savings" for the largest programs, as required by the CPUC.[99] Quarterly and annual reports prepared by the utilities following this process appear on a public website: the Energy Efficiency Groupware Application ("EEGA").

California's process is highly transparent and involved, which allows for ongoing public review. Audits are conducted at each step by contractors selected by the Energy Division (in 2004-2005 the IOUs were allowed to select their own auditors, but this policy was changed) and other interested parties. Evaluations of DEER were being made continuously, prior to being frozen for the current program cycle. DEER is available to the public and shared by utilities in an "open source" approach. On-site inspections are also conducted by third-party contractors selected by the Energy Division to verify the inputs and impacts claimed by the utilities; however, these field tests are only conducted for the largest programs.

Evaluating and Monitoring Adjustments

Free-ridership, spillover, and persistence are tracked and measured by jurisdictions to better understand the impact of DSM programs on energy consumption, though with varying degrees of rigor. In Canada, gas distributors in Manitoba and British Columbia make adjustments for free-ridership. Manitoba measures the size of this adjustment by distributing surveys to residential customers and by including questions on commercial applications. Gaz Metro in Quebec tracks persistence; however, no Canadian provinces currently track spillover.[100]

Massachusetts commissioned a study to help standardize the reporting of free-ridership and spillover,[101] while Iowa asks that utilities *estimate* the effect of free-riders, persistence, and take-

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99 California Public Utilities Commission, Energy Division, "Energy Efficiency 2006-2007 Verification Report," November 18, 2008, p. 19-24 and California Public Utilities Commission "Progress Report to the Legislature," July 2009, p. 14.

100 IndEco, "DSM Best Practices Update," p. 65.

101 National Grid, NSTAR Electric, Northeast Utilities, Unitil, Cape Light Compact, "Standardized Methods for Free-Ridership and Spillover Evaluation – Task 5 Final report," June 16, 2003.

back.[102] California tracks free-ridership for net-to-gross calculations as well as the "interactive effects" (or spillover) of CFL programs.[103] This allows the California PUC to make a decision regarding the effects of spillover, but does not bind it to make such a determination.

Two states, however, have noticeably taken a step back from the use of some of these adjustments in evaluating programs, though for different reasons. Minnesota recognized that the process for tracking these factors is difficult, expensive and still carries a relative degree of uncertainty. In order to suppress growing EM&V budgets, the Commission allows utilities to assume that free-ridership is cancelled out by free-drivership. This methodology is supported by the ACEEE.[104]

California continues to track free-ridership and spillover, but no longer bases performance incentives on the findings. Refusing utilities credit for installing measures that resulted in energy savings, even if the measure would have been implemented by a customer without prompting, was deemed unfair. Instead, the California PUC is basing goals for 2010-2012 on "total market gross" savings rather than "net savings," which adjusts for free-ridership. California will continue to track free-ridership and look for ways to reduce it, but has moved away from relying on the factor when evaluating programs.[105]

The methodologies used to measure savings, spillover and other metrics, differ among jurisdictions. Some regulators require the utility to create its own individual plan and make its own reasonable assumptions to measure the impact of DSM programs, as in Iowa.[106] New York utilities, similar to Ontario, create their plans and assumptions with assistance from Staff and with guidance from an Evaluation Advisory Group consisting of stakeholders and program administrators. Other jurisdictions prefer to centralize the assumptions that are used for inputs into a single database, which each utility must draw from in creating its projections and reporting its results, as in Minnesota and California. Oregon and Wisconsin have a statewide energy efficiency administrator which creates and oversees EM&V programs. New Jersey similarly has a statewide energy efficiency

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102 State of Iowa, 199.3538(2)(c).

103 California Public Utilities Commission, "Progress Report to the Legislature," July 2009, p. 20-21.

104 State of Minnesota, Office of the Legislative Auditor, "Energy Conservation Improvement Program," Report No. 05-04, January 2005, p. 35.

105 California Public Utilities Commission "Progress Report to the Legislature," July 2009, p. 14.

106 State of Iowa, 199.3538(2)(c).

utility, but it enlists the help of Rutgers University in tracking gas energy savings in the state. Connecticut's Energy Conservation Management Board, another statewide administrator, contracts with independent third parties to monitor progress.

Precision vs. Cost of Evaluating Conservation Programs

While all jurisdictions have an explicit interest in defining DSM benefits, different balances are struck between precision and cost. Determining the precise impact of DSM programs on gas consumption is a consistent focus of regulators. It is important to demonstrate to ratepayers and other stakeholders the costs and benefits of these programs. Accurate measures are also important when determining the level of financial incentives, if applicable. However, pursuing precision typically comes at a cost of more studies, more reporting, and more evaluations. Wisconsin, for example, places a high priority on precise measurement of results.[107] They *track* "Gross Reported Savings (as reported by administrator)," "Verified Gross Savings (verified by an independent third party)," "Verified Net Savings" (savings reduced to only those which can be attributed to a DSM measure – eliminating "free-ridership" and "spillover", for example), "Lifecycle Savings" (verified savings linked to a measure's life), and "Persistent Savings" (savings which decay exponentially). Focus on Energy *reports* first year reported gross, verified gross, and verified net savings; lifecycle verified gross and verified net, and persistent verified net. Each calculation represents additional resources being assigned to EM&V. Please see Section XIII (Issue #6) and Table 18 which addresses spending caps on budgets for evaluation and monitoring of DSM programs.

Evaluation of Program Results

Most jurisdictions contract with an independent third party to perform program evaluations, citing a possible conflict of interest with the former approach. Where a third party is contracted to audit program performance, multiple approaches have been observed in terms of how the third party is selected. In Maine, New York, Washington, and Wisconsin, the program administrators select their own evaluators. In California, New Jersey, and the Great Britain, on the other hand, regulatory agencies select the independent evaluators, typically with the program administrators providing input. Distribution companies in both Manitoba and Quebec conduct internal independent audits of conservation programs, with a separate department within the utilities' operations (i.e. –

[107] State of Wisconsin, Focus on Energy, "Semiannual Report (First Half of 2008). Final: October 22, 2008." 1-1, 1-3.

Accounting) conducting the evaluations. In Connecticut, the Energy Conservation Management Board is responsible for selecting independent contractors to evaluate and report on conservation program results.

Under the amended DSM framework, Massachusetts has adopted a hybrid evaluation approach. For each program cycle, the state's Division of Energy Resources ("DOER") determines which programs will be evaluated. Once certain programs have been selected for evaluation, the utilities undertake the day-to-day management of program evaluations, with the results then jointly verified by the utilities, the DOER, and the Energy Efficiency Advisory Council on a statewide basis. Finally, cyclical audits of evaluation results and processes are conducted and reported on by fully-independent third party auditors.

### d. Recommendations

Concentric recommends that the OEB appoint the entities that are responsible for conducting the independent program evaluation and the third-party audit of program results. This approach would be expected to enhance transparency, confidence and trust among stakeholders that the DSM program evaluation and the program audit were being conducted by independent entities chosen by the OEB. Concentric believes that it is appropriate for the utility to continue to pay for the program audit and the program evaluation, and to continue to recover that cost through the designated cost recovery mechanism.

Concentric anticipates that the Board would be responsible for selecting the program evaluator(s) and the program auditor, for defining the parameters of the evaluation and the audit, and for reviewing the results. Concentric believes the Board should consider assigning one or two OEB staff members to oversee the DSM program and evaluation audit process, thereby minimizing the impact of this recommendation on the Board's limited resources.

In selecting the third-party auditor, Concentric recommends that the OEB attempt to balance the need for expertise in verifying DSM program results with the need for independence. Certain stakeholders have expressed concern that the third-party auditor may not be truly unbiased if it typically represents the interests of regulated utilities. However, it is important to select an auditor that possesses the qualifications and expertise to evaluate and verify the reported results.

## XVIII. ISSUE #11: FILING AND REPORTING REQUIREMENTS

### a. Existing DSM Framework in Ontario

Under the Board's existing DSM Framework, Enbridge and Union must file applications for approval of their respective DSM plans incorporating the requirements contained in the decisions from the 2006 generic DSM proceeding. Gas distributors are also required to file an annual Evaluation Report on the activities and results of the DSM programs undertaken, summarizing the savings achieved, budget spent and the evaluations conducted in support of those numbers. An independent third party audit of the Evaluation Report is required. The auditor is retained by the utility.

Gas distributors are also required to file annually with the Board an audited report of the actual results of its DSM programs compared to the Board-approved DSM plan, with an explanation of any variances.[108]

The Draft DSM Guidelines propose detailed filing requirements for applications for (1) program funding through distribution rates, (2) LRAM, (3) SSM and other incentive mechanisms, and (4) adjustments to an approved DSM plan. The Draft DSM Guidelines propose separate filing requirements for each type of application.

In addition, the Draft DSM Guidelines propose that a gas distributor's Evaluation Report consist of the following elements: 1) a general overview of the distributor's DSM initiatives; 2) an overview of the effectiveness of the distributor's DSM plan; 3) an indication of what has been learned over the course of the DSM program, with the objective being 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; and 4) a summary of the distributor's performance relative to the DSM plan approved by the Board.

The evaluations would continue to be reviewed by an independent third party auditor engaged by the distributor. The Draft DSM Guidelines propose that the auditor: 1) provide an opinion on the

[108] See Section 2.1.12 of the Board's Natural Gas Reporting & Record Keeping Requirements Rules for Gas Utilities. These rules set the minimum reporting and record keeping requirements with which a natural gas distributor must comply.

cost effectiveness results that are material to the LRAM, SSM and other financial incentives proposed; 2) confirm that the utilities have undertaken program evaluations according to the approved Evaluation Plans; 3) review the evaluation reports and ensure the distributor has used the most recent results from program evaluations; 4) verify customer participation levels; 5) confirm that input assumptions are those that have been posted on the Board's website; 6) review the reasonableness of any input assumptions that are different than those posted on the Board's website; 7) recommend any forward-looking evaluation work to be considered; and 8) recommend any improvements to the DSM program to enhance program design, performance and customer participation.

Where utilities have approved DSM funding for more than one year, a report would be filed annually summarizing the results of the previous year, and at the end of the plan term, addressing the results for the entire plan. The annual report would provide the Board and interested 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.

The Draft DSM Guidelines propose that the annual report include the following: 1) a general overview of each distributor's DSM initiatives; 2) an overview of each program, including the targeted customer class, the program objectives, and any activities associated with the program; 3) the number of participants for each DSM program; 4) the annual and cumulative energy savings attributable to each program; 5) a description of any research regarding deemed energy assumptions and free rider and spillover estimates; 6) a statement that outlines the expected LRAM claim for the year; 7) a statement that outlines the expected SSM or other incentive claims for the year; and 8) any additional information, including an assessment of the success of programs to date, what activities are planned for subsequent years, and any planned modifications to program design or delivery.

b. Stakeholder Comments

Certain stakeholders urged the Board to develop detailed reporting requirements that would enable a thorough review by an auditor and would justify the Board's reallocation of the DSM budget. Further, they suggest that utilities be required to file detailed information concerning any DSM benefits for which the utility plans to claim credit under attribution rules.

Union supports the provisions included in the Draft DSM Guidelines that would require the development and filing of an Evaluation Plan. The company also supports annual Evaluation Report filings, and agrees that items material to LRAM, SSM, and any other financial incentives should be filed with an accompanying opinion from a third party auditor.

c. Approach in Other Jurisdictions

Annual Reporting Requirements

Each of the 16 jurisdictions reviewed in our research that require gas distributors to offer ratepayer-funded energy efficiency and conservation programs has established formal systems to report on and evaluate program activity.

Program administrators (i.e., distribution companies, energy efficiency utilities, private contractors, etc.) are responsible for reporting to their respective regulatory agency on the status of conservation programs. These reports are typically filed on an annual basis; however, in certain jurisdictions additional reporting is required on a more frequent basis. In Manitoba, California, Massachusetts, and Oregon, program administrators are also required to publish quarterly reports on the status of conservation programs. The main function served by a regular reporting requirement is to measure program performance against the goals and targets established at the beginning of the program period. Reports commonly include program descriptions, information on recent program activities, budgets and energy savings, participation levels, as well as cost-effectiveness calculations for the past program year.

In three of the jurisdictions (i.e., Connecticut, Iowa, and Maine) an additional level of reporting is required. In each of these jurisdictions, the regulatory agencies[109] responsible for energy efficiency and conservation programs must submit periodic reports on the status of such programs to the state legislature. Connecticut and Maine require these reports to the legislature on an annual basis.

[109] In Connecticut, the Energy Conservation Management Board (ECMB) is responsible for reporting to the legislature, not the distribution companies.

Frequency of Evaluation Reports

In most jurisdictions, program evaluations are conducted and reported on annually, but there are numerous exceptions. In Connecticut, annual evaluations are supplemented by monthly evaluation reports. California evaluates its energy efficiency and conservation programs every two years whereas, in Quebec, Gaz Metro prepares an Evaluation Report every three years. As Maine transitions to a new DSM framework, the designated program administrator—Efficiency Trust Maine—will arrange for each program with a budget of $500,000 or more to be evaluated at least once every five years.

d. Recommendations

Concentric endorses the OEB's proposed annual reporting and evaluation reporting requirements. We believe that the Evaluation Report and the Annual Report, as described in the DSM Draft Guidelines, will provide the Board with the necessary information about the success of DSM programs without imposing unnecessary costs and administrative burdens on gas distributors. In Concentric's opinion, the reports are collecting appropriate information for the Board and stakeholders to evaluate and assess the approved DSM programs and measures. Additional reporting requirements would not improve the Board's oversight. Conversely, it does not appear that any of the requested information could be eliminated without compromising the ability of the Board to fulfill its regulatory mandate to monitor and evaluate these DSM programs. As noted under Issue #10, Concentric recommends that the OEB appoint the entity that is responsible for conducting the independent program evaluation and the third-party audit of program results.

## XIX. ISSUE #12: DSM STAKEHOLDER INPUT

### a. Existing DSM Framework in Ontario

The Board's existing DSM Framework indicates that distributors should engage and seek advice from a variety of stakeholders and experts in the development and operation of their DSM programs. However, the gas distributor is ultimately responsible for the development and delivery of cost effective DSM programs in its franchise area, and stakeholders serve in an advisory capacity. At a minimum, each distributor is expected to hold two DSM Consultative meetings per year. All intervenors in the distributor's most recent rate case should be invited to participate in these DSM Consultative meetings. The purpose of these meetings is: 1) to review annual DSM program results; 2) to select an Evaluation and Audit Committee; and 3) to review the completed program evaluation results.

The existing DSM Framework specifies that the EAC should provide formal input into the distributor's Evaluation Plan, and should have an advisory role on the following matters: 1) consultation prior to filing of the DSM plan on evaluation priorities over the lifetime of the plan; 2) reviewing and commenting on evaluation study designs; 3) reviewing the scope and results of evaluation work completed on new programs introduced over the course of the DSM plan; 4) selecting the independent auditor to audit the Evaluation Report and determining the scope of the audit; 5) following the audit, reviewing the Evaluation Plan to confirm the scope and priority of identified evaluation projects; and 6) involvement in the preparation of the distributor's annual report.

The Draft DSM Guidelines do not propose any changes to the existing stakeholder consultation process.

### b. Stakeholder Comments

Certain stakeholders have suggested that the Board's annual review of DSM plans should include an evaluation of the role of the DSM Consultative (including the role of the EAC), as well as direction to the utility for how to incorporate input from both entities into DSM program development, program evaluations and the approval of results. Other stakeholders believe that value could be achieved by the Board developing its own audit capability or retaining third party experts to review the DSM data provided by distributors. Enbridge contends that because the utilities are responsible and accountable for their DSM activities, it is imperative that the role of stakeholders, either through the DSM or its EAC, be advisory in nature.

c. Approach in Other Jurisdictions

Of the 20 jurisdictions reviewed for this report, ten have relatively formal processes for involving stakeholders or the general public in the design, implementation, or evaluation of DSM programs. Stakeholder involvement in these ten jurisdictions often pertains only to the development of DSM plans and does not address program evaluation, as is the case in California, Massachusetts, Maine, Minnesota, and Manitoba. States such as New York, New Jersey, and Washington have advisory councils composed of consumer advocates, utility representatives, and other interested parties that provide input and feedback to regulators. In New Jersey, this feedback is provided throughout the DSM program evolution, including planning, program implementation, and assessment phases. In Quebec, Gaz Metro has a defined process for involving stakeholders in all phases of DSM programs on a quarterly basis, but this involvement occurs outside the regulatory process. The remaining ten jurisdictions involve stakeholders only informally, on a volunteer basis, or not at all.

Connecticut has one of the most inclusive and progressive methods of involving stakeholders in the development of DSM programs. Connecticut's ECMB advises utilities in the development and implementation of cost-effective DSM and conservation programs. Community and stakeholder involvement in ECMB activities is incorporated in five major ways.[110]

1) *Opportunity for Public to Present Comments at ECMB Meetings*

Stakeholders and community members are given an opportunity to provide input and feedback at the beginning of each meeting. Notice of ECMB's meetings, which are open to the public, is posted on the Connecticut Department of Public Utility Control ("DPUC") website at least 5 days prior to each event. Meeting dates are also published regularly in community and business publications. In addition, the ECMB Technical Coordinator maintains an email list of interested parties so that participants can be notified of upcoming meetings.

2) *Focused Topic Discussions at ECMB Meetings*

[110] Discussion of opportunities for stakeholder involvement in Connecticut is adapted from "Energy Conservation Management Board – Mission, Structure and Rules," updated July 8, 2009.

At times, the ECMB will dedicate an entire meeting to a specific DSM program, market, or other issue. In such cases, meeting agendas are posted in advance to the DPUC website. Very often, experts or organizations with experience or interest in the relevant topic will be invited to present during the meetings. As in all ECMB meetings, there is an opportunity for stakeholders and community members to provide comments or ask questions.

3) *Public Forums*

The ECMB sponsors public forums on an annual basis to solicit public input on both new and existing DSM programs. The forums provide an opportunity to review and discuss existing residential, low income, commercial, and industrial programs, and to propose new programs.

Early in the planning process for a future program year, the ECMB sponsors a forum to identify and explore new program concepts. Public forums are also held later in the program development process to provide stakeholders with a venue in which to present comments on draft program plans and budgets for new projects.

4) *Consideration of Specific Products/Technologies or Program Revisions*

If a product/technology or program revision is being proposed for inclusion in a Conservation and Load Management ("C&LM") program, the ECMB encourages the proposer to request that the utility administrators review and assess its feasibility, appropriateness, potential effectiveness, and cost-effectiveness. The ECMB believes that the vast majority of proposals should be reviewed by the utilities in their role as program administrators, and that this will be the fastest and most efficient review process.

If the proposer is not satisfied with the utility review and assessment, or if the proposer chooses not to submit the product or program revisions for utility review prior to ECMB review, then the ECMB will assign the proposal to a standing committee to review the product or program revision. The ECMB standing committee will be comprised of five members, including one business representative, one representative of a state agency that is a consumer representative, one representative of either environmental or low income organizations, and two utility representatives.

Individuals or organizations that are not satisfied with the Board's treatment of proposals for products or program revisions have the option to petition the Department to participate in the annual DPUC proceeding in which the C&LM program plans are reviewed.

5) *Public Review of Reports and Plans*

A variety of progress reports are required to be filed by the ECMB and utilities at specified intervals. These periodic reports are made available for stakeholder review:

- The ECMB submits a report to the CT state legislature each January.
- Gas utilities provide reports on program performance on a quarterly basis.
- Draft DSM plans (prepared by the utilities) are published several months prior to filing with the DPUC.

d. Recommendations

Concentric endorses the OEB's current approach to soliciting stakeholder input. From our perspective, the Board's existing DSM Framework strikes the appropriate balance between allowing stakeholders the opportunity to participate in the development, design and evaluation of DSM programs while recognizing that gas distributors are ultimately responsible and accountable for these programs. A multiple step process, such as the one used in Connecticut, appears to promote stakeholder involvement and public comment, but also has the potential to slow down the development and delivery of cost effective or innovative DSM programs, while increasing the time spent addressing stakeholder's concerns. On the opposite end of the spectrum, jurisdictions which do not have an established process for allowing stakeholder input are sacrificing the expertise of ratepayer advocates and environmental groups, both of which can provide valuable and important perspectives.

## XX. ISSUE #13: INTEGRATION OF GAS AND ELECTRIC DSM

### a. Existing DSM Framework in Ontario

There is no formal integration of natural gas and electric conservation and demand management programs at this time, and this issue has not been addressed in the Board's existing DSM framework, other than as it relates to the attribution of benefits (or savings) as described in Issue #4 above.

In practice, however, there has been some cooperation at the program delivery level, but not at the program design level. For example, Toronto Hydro partnered with Enbridge for the delivery of Enbridge's Technology Awareness Program. This program targeted reductions in hot water use by providing homeowners with low-flow showerheads, pipe insulation, bathroom and kitchen faucet aerators, regardless of whether the customer had an electric or natural gas water heater. In addition, compacts fluorescent lights were distributed to homes visited.

### b. Stakeholder Comments

Certain stakeholders have proposed that natural gas and electricity conservation programs should be integrated in order to reduce customer confusion, increase customer participation and reduce delivery costs.

In mid-2009, the CWG developed a set of guiding principles for natural gas utilities in developing low-income DSM programs in 2010 and beyond. One principle that received wide support from the group was that whenever possible, the utilities should work with municipal and provincial social services agencies to provide assistance to low-income customers in addition to providing integrated and coordinated delivery of gas and electric DSM programs to the degree feasible. One participant took issue with the language adopted by the CWG with respect to gas and electric DSM integration because it found the requirement to be less aggressive than necessary.

### c. Approach in Other Jurisdictions

There is wide variation in the degree to which state and provincial policies require collaboration between natural gas and electricity conservation and demand management programs. Some jurisdictions explicitly require combined programs, and others require clearly separate efforts. Most, however, fall somewhere between these two extremes, allowing companies to increase the effectiveness of certain programs by combining efforts when possible through policy or voluntary collaboration.

New Jersey, Maine, Connecticut and British Columbia each have a single policy initiative or set of DSM programs that applies to both gas and electric utilities. This creates administrative synergies and economies of scale for companies wishing to combine efforts for different kinds of customers. While our research has not revealed any evidence that integration of gas and electric DSM programs has improved customer participation or reduced customer confusion, as discussed below, some jurisdictions are proceeding based on the expectation that such benefits may be achieved. Wisconsin states that the third party administrator of DSM programs "makes it easier for consumers to find energy efficiency programs ('one stop shopping')". Beginning in 2010 in both British Columbia and Connecticut, gas and electric distributors will work together to implement conservation programs. In Connecticut, the utilities, the Energy Conservation and Management Board, and stakeholders will work together to identify focus areas and budget priorities for DSM. This collaboration will extend to implementation as well. Experience in the state has shown that by leveraging combined efforts of both types of programs (i.e., natural gas and electric), utility conservation programs will have a considerably greater impact.

In California, the same plans cover gas and electric utilities. Diversified utilities (PG&E, SDG&E) have achieved synergies by creating programs designed to facilitate economies of scale. Companies focused on a single market, such as Southern California Gas and Southern California Edison have found that by collaborating, the two companies can increase program efficiencies, combining efforts in certain kinds of programs (e.g., home energy audits).

Other jurisdictions permit combined programs, but do not require them. In Manitoba, New York, Wisconsin, Iowa and Oregon, programs are overseen by a single entity. This provides utilities in those regions an opportunity to combine programs to the degree possible. In New York, the Public Service Commission has directed companies to integrate gas and electric program delivery where feasible. The Commission reviews plans in phases, focusing on market segments individually to evaluate whether particular kinds of programs can address both markets simultaneously.

In still other states, there is limited collaboration. In Colorado, diversified utilities may submit plans and documentation for combined programs, but there is currently no statewide plan that aims specifically to capture efficiencies by combining these efforts. In Massachusetts, under a new 3-year planning cycle, gas and electric utilities are bound by the same set of policies regulating target setting, program evaluation, etc. However, by law the two types of programs must be administered by different Program Administrators. Despite this separation, Program Administrators have expressed their intention to develop a common customer experience that can be monitored, measured, and enhanced seamlessly. This way, electric and natural gas measures can be evaluated consistently. Coordination and integration of activities that are designed to serve both natural gas and electric customers is not new to Massachusetts. Program Administrators have engaged in such practices informally in the commercial and industrial market sectors, for example.

Nova Scotia is in the process of establishing a non-profit organization (Efficiency Nova Scotia) that will administer both electricity and natural gas conservation and efficiency. The program offerings of Efficiency Nova Scotia have yet to be determined. Prior to this legislation, energy efficiency and conservation (electric and gas) programs were administered by Conserve Nova Scotia - a Special Operating Agency of the province of Nova Scotia reporting to the Ministry of Energy. Existing electric energy efficiency programs are financed by ratepayers, while existing natural gas conservation programs are taxpayer-funded.

In Washington and Quebec, there is almost no collaboration between gas and electric utilities, by policy fiat or otherwise.

d. Recommendations

The integration of gas and electric DSM programs appears to offer some benefits in terms of reducing administrative costs associated with separate programs, and may improve penetration of some programs. Concentric questions whether integration can occur successfully in Ontario, where there are two natural gas distributors and approximately 80 electric distributors in Ontario that are regulated by the Board. The level of coordination and cooperation required to achieve true integration might be untenable, absent a central administrator. However, the Board might wish to encourage utilities to integrate certain phases of their DSM programs, such as program delivery (e.g., home energy audits) or low-income community programs. Home energy audits offer a significant opportunity for cost synergy because the potential for both natural gas and electric savings can be assessed in the same visit. Concentric recommends that the Board consider ways in which gas and electric utilities can coordinate, if not integrate, their DSM programs to improve customer participation and to achieve certain administrative efficiencies.

We further believe that DSM programs for low-income customers that are implemented on a community basis provide a unique opportunity for cooperation between gas and electric utilities to capture synergies in communications and delivery of programs. Pilot programs on an individual community basis represent an appropriate start to such an initiative.

## XXI. ISSUE #14: ALTERNATIVE DSM FRAMEWORK(S)

### a. Existing DSM Framework in Ontario

The OEB is reviewing its existing DSM Framework. OEB Staff issued Draft DSM Guidelines for Natural Gas Distributors on January 26, 2009 in EB-2008-0346, and stakeholders have filed written comments in response to those proposed guidelines. The Board, with the assistance of a consultant, has developed input assumptions to be used in the development of DSM plans and programs. The Board is considering whether further revisions or modifications to its existing DSM Framework, or to the parameters or elements of that framework, are warranted, especially in light of the recent passage of the Green Energy Act in Ontario.

### b. Stakeholder Comments

Some representatives of ratepayer interests believe that the current DSM Framework has failed and should be replaced by a fundamentally different framework, which will require re-thinking how DSM is measured, what shareholder financial incentives are provided, and the role of gas distribution companies in program development, delivery and evaluation. They argue that the current DSM framework is using an "artificial construct" that relies heavily on input assumptions to calculate results and incentives for distributors. One ratepayers' representative characterized the current DSM framework as having the following disadvantages:

- Requires an enormous amount of time, effort and money on the calculation of costs and benefits;
- Is quite complex and the complexity promotes game playing on the part of the utilities and stakeholders;
- Engenders distrust and animosity between utilities and stakeholders; and
- Makes ratepayers cynical about DSM activities.

The same ratepayer representative proposed an approach where DSM activities would be evaluated based on "top down" empirical evidence related to reduction in normalized average gas consumption per customer class or specific end-users.

Other stakeholders have argued that the current DSM Framework is outdated and ill-suited because there are several layers of government, various utilities, non-governmental organizations and private companies who deliver conservation programs.

Representatives of environmental interests, as well as gas distributors, generally support the existing DSM framework, with certain modification and adjustments.

One ratepayer advocate argued that the current DSM Framework should be reconsidered due to the "time, effort and complexity involved in setting the DSM parameters and measuring results. They continue: "The very fact that the LDCs have LRAMs and SSMs has made the evaluation of results extremely important, but also extremely contentious." This stakeholder believes that it would be possible to implement a simpler system, and that such an effort should be investigated, and potentially undertaken.

c. Approach in Other Jurisdictions

Revisions to Existing DSM Framework

Many jurisdictions across Canada and the United States are currently reviewing, or have recently reviewed, their DSM framework and policy approach. The primary impetus for this flurry of activity by regulatory agencies appears to relate to the perception that DSM programs are an increasingly important tool to combat climate change, at least until more renewable energy supply becomes available or new nuclear facilities are constructed. The emphasis on reducing carbon emissions by conserving energy has gained momentum across many different jurisdictions in our research sample.

Several jurisdictions have recently implemented a DSM framework or articulated a formal DSM policy approach for natural gas distributors for the first time. For example, in June 2008, the New York PSC issued an order that authorized a system benefit charge of $13.2 million annually through 2011 and required gas utilities to submit proposals for "fast-track" residential HVAC programs to initiate short-term gas efficiency efforts. In May 2009, New York established long-term, statewide targets for natural gas energy efficiency programs funded through the newly-authorized surcharges. The targets are set at 4.34 Bcf annually through the end of 2011 and 3.45 Bcf annually from 2012 through 2020. The estimated annual cost of statewide gas efficiency programs is $130 million. In Colorado, House Bill 07-1037 required the Colorado PUC to set energy savings goals for natural gas distributors. The Commission initiated a rulemaking proceeding to revise its existing rules for gas DSM, which had previously applied only to the low-income customer segment. The new rules require gas distributors to file biennial DSM plans and energy savings targets for both residential and commercial/industrial customers. In Washington, a recent voter initiative (Initiative Measure No. 937) requires energy saving goals. Gas utilities are required to contract for studies that will determine their total savings potential through 2019, and to establish biennial goals by January 1, 2010. Although there is no statewide framework for gas DSM at this time, the Washington Commission has been promoting energy efficiency by using conservation as a bargaining chip for utilities requesting approval of decoupling mechanisms.

Increased Environmental Focus

As noted elsewhere in this report, the original purpose of gas DSM programs was conservation and energy savings through more efficient use of natural gas. However, that purpose is evolving in many jurisdictions to include environmental concerns such as climate change, and DSM programs are being viewed as an interim solution to reduce carbon emissions and greenhouse gases. As this evolution occurs, some jurisdictions are finding it necessary to re-assess whether the regulatory agency should set more aggressive energy savings targets and whether the existing DSM framework is adequate to achieve the new policy objectives. In Massachusetts, for example, the 2008 Green Communities Act created the Energy Efficiency Advisory Council ("EEAC") to help utilities develop a statewide energy efficiency plan. The Act transitions utilities away from the previous system in which each gas distributor submitted an energy efficiency plan every five years with annual adjustments to a new system where utilities jointly file a statewide plan every three years with annual adjustments.

Utility vs. Third-Party Administration

There is continuing debate across jurisdictions in Canada and the United States regarding whether DSM programs should be administered by the gas utilities or a third party administrator. Some jurisdictions appear to have determined that a third party administrator is more cost effective, especially in terms of delivering DSM programs on behalf of small gas utilities that may not have the economies of scale necessary to achieve savings targets in an efficient and cost effective manner. Other states, notably California, have concluded that they prefer that the gas utilities design, deliver and administer DSM programs. In Maine, 2009 legislation (LD 1485) has precipitated an overhaul of the existing DSM framework. Utility-administered DSM programs will be transitioned to a central agency that is responsible for approving and administering all gas and electric efficiency programs.

In Wisconsin, the framework was modified in 2005 by Act 141, which gave utilities the responsibility for creating and administering DSM programs. In response, the utilities unilaterally created a third party administrator and continue to implement DSM programs in this way. Despite this attempt to move away from a third party administrator, the program is essentially the same as before, except that utilities are now ultimately responsible and accountable for the program results. Oregon and New Jersey have long relied on a third party to administer DSM programs, and appear to be satisfied with the results.

d. Recommendations

Concentric does not offer any specific recommendations with regard to alternative DSM frameworks. In our opinion, the evidence related to the relative merits of third-party administrators is inconclusive. If Ontario's DSM program was failing to achieve the Board's policy objectives, then it might be reasonable to consider whether the administration should be turned over to a third party entity. However, we have not seen evidence suggesting this is the case. We agree with stakeholders that the DSM framework in Ontario could be enhanced, but we do not believe that the current framework should be abandoned and replaced by something entirely different. Rather, we recommend modifications to the existing framework, and to the parameters of that framework.