EB-2008-0346

Gas DSM Framework Review

GEC RESPONSE

TO BOARD STAFF'S PROPOSED DSM GUIDELINES

GEC represents over 125,000 Ontario residents who are members or supporters of its member organizations: the David Suzuki Foundation, Greenpeace Canada, Sierra Club of Canada and WWF-Canada. GEC has limited its comments to matters where we have a particular concern with the recommended guidelines and to matters where we anticipate significant debate among the intervenors.

3.0 Program Design (Discussion 3.3.1)

Board Staff suggest that the utilities must apply for Board approval in the event that they wish to transfer more than 30% of the budget for an individual DSM program to others. GEC supports restrictions on the ability of the utilities to transfer funds from low income and market transformation programs to resource acquisition programs, because the utilities will often have financial incentives to make such transfers at the expense of treating the most disadvantaged of ratepayers and/or under-investing in efforts with longer-term pay-offs. However, within the portfolio of resource acquisition programs, GEC believes that utilities should have more flexibility than implied by Board Staff's draft guidelines. If market feedback suggests that one program is not working nearly as well as expected, a program is working much better than expected, or a fundamental change in the market has occurred since the program was approved (e.g. a significant downturn in housing starts reduces opportunities in a residential new construction program), it is important that the utilities have the flexibility to adjust course (even potentially including eliminating a program) quickly. Requiring Board approval will preclude such nimbleness, creating significant disincentives to make appropriate changes and therefore, resulting in lower performing DSM portfolios. The only rationale for accepting reductions in nimbleness and performance by requiring Board approval for changes to the resource acquisition portfolio is to ensure that equitable access to DSM offerings remain for all customers. Thus, GEC suggests that the Board put limits only on the ability to shift budgets between sectors (residential, commercial, industrial, and multi-family) without Board approval. However, in such cases, we suggest such limits be more like 10% of the budgets for each of those sectors.

4.4 R&D (Discussion 3.4.4)

Board Staff rejects a separate fund for R&D, suggesting that any funding for R&D should be "supported by the budgets associated with one or more of the three generic types of natural gas DSM program (i.e. resource acquisition, low income and market transformation)". The problem with that approach is that R&D does not generate savings in the near term. Thus, every dollar the utilities spend on R&D will reduce their ability to meet short-term goals and earn shareholder incentives. As a result, they will always have a strong incentive to under-invest in R&D. GEC submits that this conflict will tend to limit innovation and learning. That might be acceptable if the Board's only interest was in near term savings. However, the Board clearly has an interest in minimizing energy bills in the long term as well as the short-term. In addition, both the government's stated interest in building a "culture of conservation" and the need to significantly reduce carbon emissions in the coming decades suggest that at least a modest level of investment in efforts designed to lay the foundation for more effective future efforts to capture cost-effective efficiency savings is warranted. Accordingly, GEC suggests that the guidelines should provide for a modest segregated R&D budget (i.e. 2% to 3% of total DSM spending) which must be justified in the LDC plans but which is not transferable to other program efforts and is subject to the DSMVA if unspent.

5.1.2 Program Costs

Staff's discussion of program costs to be included in program screening is thorough and accurate. However, there is an aspect of administration costs that is not addressed with sufficient clarity. Some administration costs cannot be attributable to individual programs. That is, elimination of a program would not eliminate the need for a DSM manager or some basic elements of a DSM tracking and reporting system. Those administration costs should be included in screening only at the portfolio level.

5.1.3 Modified TRC Test Calculation

Staff recommends that the modified TRC take into account only avoided costs; net equipment costs; program costs; and adjustments for free ridership, spillover and persistence (as applicable). This omits a range of non-energy benefits (e.g. improved productivity, improved comfort, improved building durability, etc.) that are very real. Numerous studies have shown that such benefits are often worth more than the energy benefits. Moreover, many leading efficiency programs actively market those benefits to consumers. Thus, from a societal perspective, ignoring them results in significant under-investment in efficiency. That is the principal reason why GEC has argued for using the Program Administrator Cost Test (PACT) rather than the TRC test for determining which programs are worthy of rate-payer investment. The PACT simply compares whether rate-payer benefits are greater than rate-payer costs. Notably, that is exactly the test the Board uses when determining whether supply-side investments are cost-effective. Use of the PACT would also make cost-effectiveness analysis simpler by eliminating the need to estimate incremental measure costs (it is only the program's financial incentive that matters) and the need to invest evaluation dollars to support such estimations. For all these reasons, GEC continues to believe that the PACT is preferable to the modified TRC. Staff did not address these arguments in its discussion of which test to use. GEC submits that this option warrants further consideration.

That said, if the Board decides to require use of the modified TRC test, then it should at least permit inclusion of non-energy benefits in cost-effectiveness screening using the test to the extent such benefits can be reasonably calculated or estimated.

6.1.2 Updates to Input Assumptions During the DSM Plan

Staff's recommendations make reference to the fact that updates should include "inputs obtained through the stakeholder engagement process". However, that process is not defined. Currently, the Evaluation and Audit Committees are working closely with the utilities to develop assumptions updates. GEC submits that this process is working reasonably well and suggests that the Board formally enshrine the EAC as the mechanism through which stakeholder input will continue to be included in the future (note that GEC would support an EAC process regardless of whether the utilities or the Board manage evaluation contracts, audits and measure assumption updates).

6.1.3 Use of Input Assumptions (Discussion 3.5.1.2)

Board Staff correctly observes:

> *To this point, staff notes that based on its review of Enbridge and Union's audited DSM results from 2007 to 2009, the audited total natural gas savings used to determine incentive amounts have in all years and for each natural gas utility been larger than the audited total natural gas savings used to determine the LRAM amounts. The difference has been 7% on average, ranging from 1% to 18%.*
>
> *Using updated input assumptions instead should reward natural gas utilities to maintain a flexible approach and react to current information during the program year; an approach that would support the achievement of greater savings to everyone's benefit.*

GEC strongly supports the move to best available information for incentive calculation as it will serve the goal of program improvement, reduce the potential for gaming, and lessen controversy in the EAC process. However, this change will further discourage timely evaluation, hence our support for independent evaluation and auditing with a segregated budget for these activities.

6.2.2 Costs of CO2e Emissions (Discussion 3.5.2.2)

Board Staff asks participants to provide further comments on whether they consider that any value for carbon should be included at this time. Staff notes:

> *As it would be the first time that a value for CO2e emissions is introduced, and given the uncertainty surrounding when and at what level an eventual Ontario market value would be established, staff recommends using the lower end of the range recommended by CEA. This represents a value of $15 per tonne of CO2e emissions. Staff recommends that this value be maintained at $15 per tonne of CO2e emissions for the duration of the multi-year plan term. If market developments warrant re-examining this value during the term of the plan, the Board could entertain doing so as part of the annual process to update input assumptions.*

Thus Staff propose a single, low estimate for carbon as an initial value. GEC questions the implicit assumption that carbon prices will remain low over the typical 15 year measure life of the DSM measures being delivered. If it is reasonable to assume that carbon prices, be they implicit or explicit in regulations and markets, will ramp up over time, then avoided costs should reflect an increasing carbon value over the period. GEC suggests that ramp up be equal to at least $1/year, so that the avoided costs used by utilities to screen programs include a $15 per tonne adder in 2012, increasing to $25 per tonne in 2022, $35 per tonne in 2032, etc..

7.1 Free Ridership (Discussion 3.6.1)

It is critically important than the framework for addressing both free ridership and spillover make explicit and clear that such effects are a function of the design of a program to promote an efficiency measure (or measures), not a function of the measure itself. Indeed, that is precisely why Navigant chose not to include free ridership values in its development of deemed measure assumptions for the Board.

Consider, for example, a hypothetical situation in which 100 boilers are sold each year and, absent any DSM program, 10 would be sales of high efficiency products with an incremental cost of $1000. If a utility introduced a program that simply offered a $50 rebate for the efficient product, it would likely have a very high free rider rate. Perhaps the utility would rebate 15 units, but 10 of those (or 67%) would be customers who would have purchased the product anyway (i.e. would be free riders). In contrast, if the utility offered a $750 rebate, it might get 50 participants. The 10 who would have purchased the product anyway would take the rebate, but 40 would be influenced to change their purchase. Thus the free rider rate would be only 20% (i.e. 10 out of 50) in this case.

This is not a new concept. However, to this day, the utilities often suggest that the current market share for an efficient product is a good proxy for free ridership. It is not. At best, the current market share is the "floor" (i.e the absolute lowest possible given the most aggressive program design) for free ridership. The framework would benefit from inclusion of that conclusion as well.

8. Overall Natural Gas DSM Budget (Staff 3.7.1)

GEC submits that this is the single most important issue before the Board. Budget will enable or limit the progress that the LDCs can make toward all objectives including economic, environmental and equity objectives.

Board Staff have recommended that the utilities' budgets increase to between 3.5% (Enbridge) and 4.5% (Union) of distribution revenues in 2012 and continue increasing to about 6% of distribution revenues for both utilities by 2014.

GEC has several concerns about this recommendation. First, the Staff appears to suggest that the 6% value is appropriate in part because it balances arguments made by different parties for both higher and lower levels of spending:

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

GEC finds the rejection of the option because it does not represent the 'balance of comments received' a less than satisfactory rationale. If balance of comments were the test, the consultation and hearing process would be little more than a poll of intervenors. Indeed, if representing the greatest number of Ontarians were the goal GEC would likely do well (as noted above GEC members have over 125,000 Ontario supporters, the majority of whom would be utility ratepayers in Ontario).

Further, the arguments offered by the different groups for lower and higher levels of spending are not equal on their merits. One of bases for GEC's argument for higher levels of spending was that the CEA data upon which Board Staff relies was out-dated by at least 5 years – a conclusion which CEA has conceded. Gas DSM spending has been increasing significantly in recent years and will be increasing further in the future – again, a conclusion with which CEA has agreed. As the following table – reproduced from GEC's comments on CEA's report – shows, updating the data to reflect conditions in 2012 – the first year to which a new Ontario gas DSM framework would apply – leads to the conclusion that leading jurisdictions were averaging spending of 12% of revenues.

Table 1: 2011/2012 Budgets for U.S. Utilities in Concentric Report (Table 15)[1]

		Concentric Estimates of Budgets			GEC Updates to Budgets		
Jurisdiction	Utility	Year	Budget (millions)	% of utility revenue less cost of gas	Year	Budget (millions)	% of utility revenue less cost of gas
California	SoCalGas	2008	$68.0	5.4%	2011	$158.2	11.9%
Connecticut	Southern CT Gas	2008	$2.0	1.6%	2010	$3.3	2.5%
Iowa	MidAmerican	2007	$15.8	3.9%	2012	$25.5	5.7%
Massachusetts	Ngrid	2007	$7.8	2.7%	2012	$90.0	28.2%
Minnesota	CenterPoint Gas	2008	$8.4	5.9%	2012	$22.5	14.8%
Average				3.9%			12.6%

This is a ***factual*** correction. Indeed, it probably even understates where leading utilities will be by 2014 – the year by which Board Staff recommend the Ontario utilities reach 6% – because GEC was only able to obtain budget data for other jurisdictions for 2010, 2011 or 2012. In contrast, the arguments against the CEA recommendation and in favour of spending less were not *factual* corrections. To begin with, the concern that the average spending suggested by CEA was skewed due to "the disproportionate influence of one observation in CEA's U.S. sample" is eliminated by using updated spending values. Indeed, as the table above shows, the average spending and median spending levels for utilities for which GEC was able to obtain more up-to-date spending data are both around 12%. Second, concerns that the CEA data were biased because they focused

[1] References for the GEC budget numbers are as follows: (1) Decision of Commissioner Grueneich and ALJ Gamson, Public Utilities Commission of the State of California, Approving 2010 to 2012 Energy Efficiency Portfolios and Budgets, regarding Applications 08-07-021, 08-07-022, 08-07-023 and 08-07-031, September 24, 2009; (2) 2010 Electric and Natural Gas Conservation and Load Management Plan, submitted by The Connecticut Light and Power Company, the United Illuminating Company, Yankee Gas Services Company, Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company, Docket Nos. 09-10-03 and 08-10-02, October 1, 2009; (3)MidAmerican Energy Company, Energy Efficiency Operating Plan, EEP-08-2, to the Iowa Utilities Board, Volume 1, Updated April 1, 2010; (4) Petition of Boston Gas Company, Colonial Gas Company and Essex Gas Company each d/b/a National Grid for Pre-Approval of Gas Energy Efficiency Programs and Recovery of Gas Energy Efficiency Related Costs for the Period of January 1, 2010 through December 31, 2012 – D.P.U. 90-121, Exhibit NG-6; (5) CenterPoint Energy Compliance Filing to the Final Decision on its 2010-2012 Conservation Improvement Program (CIP) Triennial Plan and Center for Energy and Environment's Proposal for the One-Stop Community Energy Services for Inclusion in CenterPoint Energy's 2010-2012 CIP Triennial Plan, Docket Nos. G008/CIP-09-644 and G008/CIP-09-291, December 30, 2009.

on leading utilities and jurisdictions are misplaced. GEC submits that a focus on leading jurisdictions is not a bias. That is the very group to which Ontario spending needs to be compared. Every initiative on energy efficiency by the Ontario government in recent years has made clear that it is the province's intent to be a North American leader. Consider, for example, the Minister's July 5th, 2010 directive to the OEB:

> *"I also urge the OEB to consider expanding both low-income and general natural gas DSM efforts relative to previous years. While mindful of the OEB's responsibility to ensure the balancing of ratepayers' interests, I would support efforts by the OEB to expand DSM efforts in general, considering the scale of investments being made on electricity CDM and the natural gas DSM experience and* ***funding levels of other leading jurisdictions****." (emphasis added)*

Thus, the CEA focus on leading utilities and jurisdictions was entirely appropriate. Put simply – and in contradiction of staff's conclusion that the spending range put forward by CEA is "a reasonable reflection of the level of DSM budgets found in those leading jurisdictions" – if Ontario is to be among the leading North American jurisdictions, it should be ramping up gas DSM spending to levels at least 12% of distribution system revenues.

As important as comparisons to other leading jurisdictions are, it is also vitally important that DSM budget levels be grounded in and driven by a set of fundamental policy principles. Staff suggests five primary guiding principles (3.7.1.3):

- Supporting an increase emphasis on deep measures;
- Ensuring equitable access to DSM programs among and across all rate classes to the extent reasonable, including low-income customers;
- Increasing coordination and integration of certain natural gas DSM programs with electricity CDM programs;
- Ensuring no undue rate impacts; and
- Ensuring no undue level of cross-subsidization within and across rate classes.

While we agree with each of these, GEC submits that three other principles are missing and should be added to the list:

A. Maximization of cost-effective natural gas savings (or alternatively, minimizing gas bills);

B. Prevention of lost opportunities; and

C. Meeting provincial policy objectives, including carbon emission reduction goals.

It is worth noting that the first two of these – maximizing cost effective gas savings and minimizing lost opportunities – were not included in Staff's list for consideration in setting budget levels despite the fact that both were among the four principles Staff proposed and noted were "broadly accepted by participants" for determining which DSM programs should be included in DSM portfolios (3.3.1). It is unclear why they would be appropriate for determining which DSM programs to pursue but not be relevant to how much to spend, when budget levels have enormous implications for which programs *can be* pursued. We are particularly perplexed by the omission of the principle of maximizing cost-effective savings – or minimizing gas bills, both goals squarely recognized in the Board's statutory objectives. One can make a pretty compelling case that the economic and policy imperatives for aggressively pursuing gas DSM are even more compelling today than when it was first adopted as a principle in the early 1990s[2]. Thus, excluding it from the list of principles that guide decision-making on budgets should be viewed as a significant step backwards for the province.

[2] See for e.g. EBO-169-III para. 10.3.4

GEC submits that when an appropriately full range of policy principles – including maximizing cost-effective savings and addressing other Ontario government policy objectives – is considered, it will quickly become apparent that spending levels should increase well beyond the beyond the ramp up to 6% by 2014 proposed by Staff. No study has been put forward to suggest that spending even 12% would be enough to capture anything close to all cost-effective savings; efforts in other jurisdictions spending more than that suggest it would not be enough. Nor will it be possible to capture deep savings for more than a small fraction of rate-payers with a spending cap of 6%, particularly now that the federal ecoENERGY program has been terminated and the provincial program is about to end. In the residential sector, the biggest cost-effective savings potential is in building retrofits (draft-proofing, adding insulation, etc.). Indeed, GEC estimates that a program designed to result in whole house retrofits of 2% of all Enbridge households per year – a pace that is roughly consistent with what the national ecoENERGY program was accomplishing in its last full year, but would still require decades before the majority of homes could be treated – could require spending on the order of $90 million per year or more.[3] That is substantially more for just one deep measures, resource acquisition program targeted to just one customer class than Board Staff have suggested be budgeted for the entire Enbridge DSM portfolio in 2014.

The only policy principle upon which the Board could theoretically rely to support not increasing spending to more than 6% of distribution revenues is concern that rate impacts would be undue. However, Board Staff's own analysis suggests that increasing spending to 6% of distribution revenues would impose a rate impact of only 0.2% to 0.4% (depending on utility and customer class).[4] Extrapolating from Staff's analysis, it appears as if increasing spending to 12% of distribution revenues would result in a rate impact on the order of 1%. It is difficult to imagine how that could be interpreted as "undue", particularly given the enormous benefits that would accrue to all rate payers over time. This highlights a problem that has existed with Board policy regarding undue rate impacts since the early 1990s. There is no clear definition of what "undue" is. GEC recommends that a "floor" for what is considered undue be established and that the floor be a 5% increase, a value that most consumers would not even notice in their bills.

In short, GEC submits that all available evidence supports a much greater increase in spending than recommended by Board Staff. Indeed, GEC submits that the increase should be as large as necessary to maximize cost-effective savings, with constraints imposed only if it could be clearly demonstrated that rate impacts would exceed 5%. GEC further submits that 12% of distribution revenues become the default assumption, as that would be much more consistent with both levels of spending in leading jurisdictions and what would be necessary to meet all of the policy principles described above. That value should be increased if analysis suggests greater savings could be obtained without undue rate impacts. It should be reduced only if analysis suggests that it could not be cost-effectively spent or if average annual rate impacts – after netting out all system benefits – could be demonstrated to exceed 5% per year.

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[3] 2% of Enbridge's residential customers would be roughly 30,000 participants per year. Our analysis assumes that the utility would spend an average of approximately $3000 per participant. That is consistent with some of the more effective whole house retrofit programs in North America. It is also consistent with the experience of the ecoENERGY program in Ontario (the combination of federal and provincial rebates exceeded $2000/home on average, to which one would need to add the costs of audits, marketing, administration, evaluation, etc.).

[4] It is unclear how these rate impacts estimates were developed. In particular, it is unclear whether rate mitigating impacts of lowering capital investments in things like storage capacity and/or lowering market clearing prices as a result of overall reductions in demand (what is called Demand-Reduction Induced Price Effects, or DRIPE, in other jurisdictions) was factored into the Board's analysis.

8.3 Budget for Market Transformation Programs (Discussion 3.7.4)

Board Staff has stated:

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

GEC generally supports a literal reading of this statement. Market transformation investments should be focused on markets where "competitive forces" are not expected to yield desired results (though the same should be said for resource acquisition programs). Gas utilities can "fill in some gaps in achieving market transformation" and should limit their pursuit of market transformation to cases where that is possible (they certainly should not invest in cases where that is not possible). Market transformation should be focused on lost opportunities and outcome-based metrics of performance.

That all said, the tone of the statement above (that market transformation is appropriate only for certain "niches" and that utility's should "limit their participation"), coupled with both concerns expressed elsewhere in Staff's report about market transformation (i.e. that it is outdated, produces results that cannot be definitively attributed to DSM efforts), and the proposed guideline that utilities spend the "largest share of the natural gas DSM budget" to resource acquisition programs leaves the impression that Staff consider market transformation efforts to be of secondary importance at best. GEC finds that conclusion problematic.

To begin with, the concern that market transformation is an outdated concept is not supported by any evidence. Indeed, jurisdictions across North America continue to pursue market transformation initiatives. The American Council for an Energy Efficient Economy continues to see growing participation in its annual Market Transformation workshop/conference in Washington, DC. (on-going since the mid-1990s).

Second, the concern that changes in markets for efficiency measures or products cannot be definitively attributed to rate-payer funded market transformation programs is not a concern unique to market transformation programs. As the Board has become aware in recent years, concerns about attribution are just as frequently raised about resource acquisition programs. That is not to say that either resource acquisition or market transformation programs produce questionable results; only that the market has become more complex and evaluators are being forced to evolve the processes by which they assess impacts.

GEC suspects that Staff's view (and perhaps that of others as well) that market transformation investments should be limited is derived from a misperception of what good market transformation initiatives do, which in turn may be derived in part from past bad experiences with poorly designed gas utility market transformation programs. Staff's characterizes market transformation approaches as those "offering conferences and tradeshows for building contractors; radio advertising targeted to natural gas customers...; and education materials distributed to schools..." GEC submits that market transformation need not and should not be limited to such "soft" elements (though these are important components of a successful approach). Indeed, just as with more traditional resource acquisition programs, some of the most successful market transformation initiatives in North America have involved substantial financial incentives, direct technical support to manufacturers and other trade allies and other "harder" elements.

Put simply, market transformation programs are not defined by the types of program strategies that they employ. Rather, they are different from resource acquisition programs in two fundamental ways:

1. they focus on longer-term results; and
2. they focus on creating fundamental changes in the market.

Those differences, in turn, require the use of different performance metrics. GEC submits that the focus on long-term savings is critically important, as the Board should be concerned about long-term benefits to rate-payers as well as short-term benefits. It may very well be that half or more of the DSM budget should be allocated to well-designed market transformation efforts. Thus, GEC recommends that the Board:

- eliminate from the DSM framework any statement regarding how much of the DSM budgets should be allocated to resource acquisition vs. market transformation programs;
- modify statement that market transformation investments "*be limited to niches"* where competitive forces will not lead to desired results to one which says such investments "should be focused on markets in which" competitive forces will not lead to desired results;
- delete phrase that utilities "*should otherwise limit their participation in this type of program"*; and
- make clear that market transformation programs must have a clearly articulated strategy that includes a description of an "exit strategy" or "transition strategy" through which market changes can be "locked in" and the program can be phased out or terminated.

8.4 Budget for Evaluation, Monitoring, and Verification (Discussion 3.7.5)

<u>EM&V Budget</u>

Board Staff observes:

> *"In staff's view, there is no evidence that the current or expected EM&V spending by the Ontario natural gas utilities may be excessive."*

Board Staff goes on to support flexibility in the EM&V budget and to reject a cap on the budget. GEC has the opposite concern, that EM&V will always be short-changed if such spending competes with incentive generating options for a limited budget and if EM&V can result in lower incentive payouts due to the revelation of poor program results or inappropriate input assumptions. Accordingly, GEC urges the Board to consider one of the following approaches:

- Transfer the EM&V role to a Board appointed evaluator/auditor with costs to be borne by the LDCs, or;
- Fix a minimum EM&V budget segregated from the program budget to ensure that LDCs do not shy away from this important work and to ensure that competition does not occur as between EM&V spending and incentive generating program spending.

<u>Stakeholder Engagement</u>

In addition, Staff suggests that the utilities incorporate input from "its stakeholder engagement process" in its EM&V planning. However, that process is not defined. Currently, the Evaluation and Audit Committees are working closely with the utilities to develop annual evaluation plans. GEC submits that this process is working reasonably well and suggests that the Board formally enshrine the EAC as the mechanism through which stakeholder input will continue to be included in the future (note that GEC would support an EAC process regardless of whether the utilities or the Board manage evaluation contracts, audits and measure assumption updates).

9. Metrics (Board Staff 3.8)

Board Staff has suggested that the need for straightforward and verifiable metrics should be balanced against the need to encourage attainment of the four objectives:

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

GEC submits that these objectives are indeed of critical importance.

For resource acquisition programs and low income programs Staff suggests a scorecard approach including:

- Cubic meters (m3) of natural gas saved;
- $ spent per m3 of natural gas saved; and
- Number of participants that receive at least one deep measure.

For market transformation programs staff would include the first two metrics as well as others specific to the market niche.

GEC is concerned that the metrics suggested will not necessarily align with the goals noted above. We offer the following suggestions and comments:

- *Cubic Meters* could be a useful metric, *but only if it is refined as lifetime savings*. For example, a measure with a two year life that generates 100 m3 of savings per year would generate 200 m3 of lifetime savings; a measure with a 20 year life that produces 50 m3 of savings per year would have lifetime savings of 1000 m3. This example highlights the fact that a focus on just first year savings would create distorted incentives to pursue inexpensive short-lived measures at the expense of more cost-effective long-lived measures.

- *$/m3* is problematic as a performance metric. The cost per unit of savings has little relevance by itself. It is of interest only in the context of overall savings and/or other policy goals. Indeed, any specific cost per unit of savings goal would need to be based on a reasonable assessment of what it would cost to meet the other goals. For example, consider a scenario in which a utility was given a goal (with associated potential shareholder incentives) of spending less than $0.20 per lifetime m3 for a portfolio that had half of its savings projected to come from programs that sought deep savings at a cost of $0.30 per lifetime m3 and half from simple programs that sought savings at a cost of $0.10 per lifetime m3. If the utility failed to meet its overall savings goals because it focused only on the simple programs, but spent $0.12 per lifetime m3 on those programs, it would earn substantial shareholder incentives – even though its cost-efficiency for the savings they effectively pursued was not good (i.e. $0.12/m3 for the portion of savings that should have cost $0.10/m3). That would be a very perverse outcome. Moreover, the utilities already have an incentive to maximize savings per dollar of spending. Doing so enables them to meet or exceed total savings or other metrics of interest. Thus, GEC submits that the Board should require that spending per unit of savings be *reported* for each program so that stakeholders and the Board can evaluate delivery efficiency in the context of particular measures and markets. However, it should not form the basis for utility goals or rewards.

- *"Participants with at least one deep measure"* is too prescriptive. This is a metric which may apply to certain programs but is not a useful metric for generic application to a range of programs, some of which may be single measure programs, others of which may have multiple deep measure opportunities. Thus, the Board should simply require utilities to work with stakeholders to develop appropriate metrics for "depth of savings" that are ideally suited to each program.

10. DSM Targets and 11. Incentive Payments

GEC is generally supportive of the targets and incentives framework proposed by Staff. However, we suggest that a couple of clarifications should be added:

- It should be made clear that the maximum incentive payment to each utility is the value that they could earn if they achieved 150% of each of their performance metrics. The value for just meeting each goal would therefore be two-thirds of the maximum payment.
- The 50%, 100% and 150% refer to the portion of the payment earned only. This is implied in Staff's example of how to compute incentives – i.e. Footnote 27 of the Draft Guidelines shows a calculation in which the performance metric for the 50% payment is more than the half of the metric at the 100% level and the performance metric for the 150% payment is less than 150% of the metric at the 100% level. This is consistent with recent practice.[5]
- Going forward, the performance metric for the 50% payout should always be equal to at least 75% of the metric for the 100% payout.
- Going forward, the performance metric for the 150% payout should always be equal to at least 125% of the metric for the 100% payout.
- There should be a clear expectation that the 100% performance target should be something of a stretch to meet with the available budget. That is, there should be a non-trivial probability that the 100% target will not be met.
- Metric results below the 50% target should be interpolated between 0 and the 50%, rather than between 50% and 100% as suggested in the draft framework.
- Multi-year targets, rather than annual targets, should be used for market transformation programs. Performance metrics, and financial incentives for meeting them, should be tied to outcomes of concern. In the context of market transformation initiatives, it is the long-term goals that really matter. Thus, either all or most of any financial incentives available to utility shareholders should be tied to achievement of longer-term objectives.

In addition, GEC wants to make clear that it does not support a cap on the portion of incentives available for market transformation initiatives. Staff's draft framework does not contain such a cap. However, its discussion paper suggests a cap of 5%. GEC views such a cap as potentially very problematic. In general, the portion of financial incentives attached to performance of

[5] For example, in Enbridge's recently approved amendment to its low income DSM scorecard, the performance goals at the 50% payout level are about 80% of the goals at the 100% payout level; conversely, the goals at the 150% payout level are about 115% of the goals at the 100% payout level.

different program types should be roughly proportional to the allocation of the total DSM budget to those program types. As noted above, there are good reasons to invest much more than 5% of the total DSM budget in market transformation programs.

15.1 Evaluation Plan (Discussion 3.12)

Stakeholder Engagement

Staff's draft framework states:

> *"The natural gas utilities, as informed through its stakeholder engagement process, have responsibility to propose appropriate monitoring and EM&V requirements. The stakeholder engagement process should set out what the formal channel will be for the gas utility's stakeholders, or a subcommittee thereof, to engage in the development of an evaluation plan and budget, and to review the evaluation results as they become available over the term of the plan."*

In other places, Staff suggests that the stakeholder engagement process should include at least two meetings every year. GEC is concerned that this language is very general and potentially opens the door to a much lower threshold of stakeholder engagement than has been the case, at least on EM&V issues, in recent years through the creation and operation of the Evaluation and Audit Committees (EACs). While not perfect, GEC submits that the EACs have functioned reasonably well on EM&V issues and recommends that the Board make clear that they should continue with a similar structure (to be amended to include involvement of Staff and to include other changes only when the utilities can make a compelling case for such changes to the Board) and at least the same level of responsibility as they current have.

Custom Project Reviews

Staff's draft framework continues current practice of requiring independent reviews of savings of a random sample of "10% of large custom projects" representing "at least 10% of the total volume savings from all custom projects". It is not clear why these 10% thresholds were selected, as they do not necessarily correlate to any statistical significance. Without statistical validity, such independent reviews have little value as the results cannot be extrapolated to the populations of custom projects as a whole. This is particularly problematic given the very large portion of savings and economic benefits currently attributable to such projects.

GEC recommends instead that the Board require that independent assessments of the reasonableness of assumptions (savings, costs and measure life) be conducted separately for custom industrial and custom commercial projects. The samples analyzed should be sufficient (including in size, stratification and other features) to draw conclusions regarding realization rates for the respective populations of each of the two groups with a confidence interval of 90% and a precision of +/- 10%.

16.1 Stakeholder Engagement Process (Discussion 3.14)

Stakeholder Engagement Requirements

Staff suggests that the stakeholder engagement process should include at least two meetings every year, part of the purpose of which would be

> *"selecting any subcommittee that* ***may*** *be part of the stakeholder engagement process;"* (emphasis added)

Consistent with other comments above, GEC is concerned that this language is very permissive and potentially opens the door to a much lower threshold of stakeholder engagement than has been the case, at least on EM&V issues, in recent years through the creation and operation of the Evaluation and Audit Committees (EACs). While not perfect, GEC submits that the EACs have functioned reasonably well on EM&V issues and recommends that the Board make clear that they should continue with a similar structure (to be amended to include involvement of Staff and to include other changes only when the utilities can make a compelling case for such changes to the Board) and at least the same level of responsibility as they current have. To simply give the utilities the option of creating EACs – as the word "may" in the quote above suggests – is highly problematic.

<u>Stakeholder Report</u>

Staff's draft framework states that a "Stakeholder Report" addressing, among other things, "the disposition of any balances in the DSMVA, LRAMVA and DSMIDA" should be filed with the Board:

> *"within 10 weeks from the date of receipt of the (utilities') Draft Evaluation Report…or the date of hiring of the auditor, whichever is later."*

This timeline is problematic. Experience in the past several years suggests that it is reasonable to expect the Auditor's report to be completed within 10 weeks of receipt of the utilities' Draft Evaluation Reports (the auditor is typically hired before the utilities' Evaluation Reports are complete, in order to enable them to "hit the ground running"). However, the audit reports never completely address all DSMVA, LRAM or SSM issues. As a result, the utilities and their EACs have subsequently worked together to develop a draft of what has been called an "Audit Summary Report" – analogous to the "Stakeholder Report" discussed by Staff – which synthesizes the work of the auditor, addresses issues that the auditor was not able to address or for which it did not feel it had sufficient information to address, and proposes an appropriate dispensation of the DSMVA, LRAM and SSM issues. The draft Audit Summary Report has then been presented for comment to the full group of stakeholders. Based on past experience, it is reasonable to expect the process to finalize the Audit Summary Report – or Stakeholder Report – to take an additional eight weeks (i.e. on top of the 10 weeks required by the Auditor to complete its work).

15.3 Independent Third Party Audit

GEC recommended a move to a Board appointed auditor/evaluator. DSM auditing and evaluation is not as straightforward as financial accounting and auditing and is therefore not as amenable to a rules based approach which can be implemented by the affected party. It is too easy for a DSM delivery entity to intentionally or unintentionally delay or starve evaluation and auditing of resources or information, and to constrain its ambit. This is particularly true where these activities compete for budget with incentive producing program delivery and where findings can reduce rewards.

While the EAC process has been very helpful at minimizing the potential for abuse, and the LDCs should be congratulated for the effort they have expended to make the EAC process successful, we believe that retention and control of both evaluators and auditors by the Board (informed by an EAC) would improve the timeliness and adequacy of EM&V.

17. Coordination/Integration of Gas and Electric Programs (Discussion 3.15)

GEC's comments on the CEA report noted that in addition to coordination of gas and electric programs, it is important for the Board to direct the gas utilities to coordinate and, wherever it would be more effective in moving the market to greater levels of investment in efficiency, integrate delivery of their programs. Such coordination and/or integration would be most appropriate for mass-market lost opportunity initiatives (e.g. sales of high efficiency HVAC equipment; sales of other efficiency products such as water heaters, gas consuming appliances, and windows; and construction of efficient new homes or commercial buildings). Integration should be essential for any market transformation initiative. Those comments are not addressed in Staff's draft framework or discussion. GEC submits that the framework should address gas-gas interactions – consistent with these comments – as well as gas-electric ones.

18.1 Filing of Multi-Year DSM Plan

GEC supports the list of items that the Staff's draft framework suggests should be included in the utilities' plans. However, we believe that there are a couple of items not included in Staff's list that should be added:

- A list of each efficiency measure to be promoted by each program;
- A list of the per unit financial incentives to be offered for each measure
- A forecast of the number of each measure that will go through each program;

This information is critical to understanding what the utilities are planning to do. As discussed above, it is also essential for assessing the reasonableness of key assumptions such as free ridership. Finally, it can help the Board and all parties focus most attention on the measures within programs that are most important.

None of this would impose any significant burden on the utilities as they will have had to generate such information already in order to appropriately budget each program.

ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 14th DAY OF FEBRUARY, 2011

David Poch

Counsel to the GEC