

Institutional and Regulatory Barriers to Utility Demand-Side Management in Canada

-Issue Paper Five-

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Energy Sector Sustainability Table**

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Preface

The Energy Sector Sustainability Table (ESST) was established in 2005 as a multi-stakeholder advisory mechanism - including senior representatives from governments, industry, and civil society – created by the Government of Canada to provide advice on how best to meet the energy needs of Canadians so as to improve the environmental and economic sustainability of energy systems in Canada and to make recommendations on short-and long-term sustainable energy objectives.

Energy efficiency was identified as key priority for the ESST so the Table established the Energy Efficiency Working Group (EEWG). The EEWG is a committee of industry, government and civil society experts mandated to provide the ESST with an expert perspective on energy efficiency in Canada. The EEWG has produced several products including its Energy Efficiency in Canada Foundation Paper, a series of issue papers, and a final report summarizing the key conclusions and recommendations that resulted from the EEWG’s work.

This issue paper is one in a series of a total of eight issue papers. The paper, as well as all other EEWG products, was prepared by the EEWG in conjunction with Marbek Resource Consultants and Dr. Michael Margolick.

To access other EEWG documents or for more information about the Energy Sector Sustainability Table and its Energy Efficiency Working Group, please visit: <http://www.sst.gc.ca>

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1. INTRODUCTION

In the 1980s and 1990s, Canadian jurisdictions participated in a worldwide trend to restructure energy markets in search of greater economic efficiency. Depending on the jurisdiction, this involved the deregulation of access to wholesale and retail markets for the commodity, the unbundling of integrated utilities into separate components for production, transportation, and retailing/marketing, the privatization of certain market players, and the economic regulation of monopoly services, such as natural gas and electricity transmission and distribution.

This restructuring exacerbated a challenge which already existed, which is: how to encourage energy Demand-Side Management (DSM) when utility revenues are linked to the amount of energy sold? Utilities that were or that remain publicly-owned could be expected to balance a desire for revenues with a mandate to promote the public good. This could be accomplished through approaches such as Integrated Resource Planning. Also, vertically integrated utilities could balance reduced revenues with reduced power production or power purchase expenses. However, in restructured markets, distribution utilities that operate on a commercial basis cannot build a business case for DSM, without some form of regulatory or institutional incentive. For those utilities, the key question is why would they pay someone not to consume their product? For society, the question is how to take advantage of the DSM opportunity, whose cost can be as little as one quarter of the cost of new supply?

In Canada, jurisdiction over energy utilities lies with the provinces. This paper examines the nature of the regulatory frameworks and institutional structures in place in three representative Canadian jurisdictions (British Columbia, Alberta and Ontario) in order to assess their impact on the incentives and disincentives for DSM. The paper borrows background information from a 2004 Report on DSM Incentives involving case studies in BC and Ontario, completed by the Pembina Institute for Appropriate Development, as well as a 2005 Discussion Paper on Regulatory Frameworks for Natural Gas DSM developed by the Conference Board of Canada.^{1,2} The jurisdictional information in these papers is updated and augmented. It is then used as a basis to identify and describe some of the key remaining barriers.

Section 2 provides background on DSM and DSM incentives. This section introduces a number of key regulatory concepts and acronyms which are an unavoidable part of the discussion (for convenience a glossary is also provided in Appendix A). Section 3 describes the institutional structures and regulatory frameworks. Section 4 assesses the barriers to DSM and identifies some opportunities to overcome those barriers. Section 5 provides areas for future work while section 6 provides a summary of the key messages.

¹ Pembina Institute. August 2004. Demand Side Management Incentives in Canada – Case Studies of Aquila Networks (Fortis BC) and Enbridge Gas Distribution. Prepared for the Office of Energy Efficiency, Natural Resources Canada.

² Conference Board of Canada. November 2005. Discussion Paper: Regulatory Framework for Natural Gas DSM in Canada.

2. BACKGROUND ON DSM AND DSM INCENTIVES³

2.1 DEMAND SIDE MANAGEMENT (DSM)

Demand side management (DSM) programs are measures to promote conservation behaviour, energy efficiency, demand-management, fuel-switching, and self-generation. Approaches include capacity-building, resource acquisition, and market transformation. The main thrust (and most easily measured portion) of most utility DSM programs is resource acquisition. This involves the promotion of more efficient technologies, practices and facility designs, using financial incentives, in which all or part of the cost increment is paid by the utility.

DSM programs costs include the cost of the efficient technology or action to the customer and the cost to the utility of the policy or program to encourage its use.

The benefits of DSM programs include reduced energy costs, capital requirements, and capital expenditures for customers; reductions in capital requirements and improved operating costs for utilities; and improved environmental, social and economic benefits for society.

The cost effectiveness of DSM can be assessed from several viewpoints — those of customers, utilities and society (and government). Several tests have been developed to measure the costs and benefits to these different stakeholders.

- The Utilities Cost (UC) test which measures the change in utility costs and revenues.
- The Ratepayer Impact Measure (RIM) test, which measures the impact of a DSM program on customer billing rates due to changes in utility revenues and operating costs. This may also be referred to as the non-participant test and is a measure of fairness.
- The Total Resource Cost (TRC) test measures the net benefits of a DSM program as a resource option based on the supply side benefits and the total costs of the program, including costs to consumers and to utilities.
- The Societal Cost Test which is similar to the TRC test, but includes a monetized value for the impact of a DSM program on emission reductions.⁴

Use of DSM in the energy sector has evolved significantly over time. Beginning with load management initiatives to reduce customer usage at time of peak demand, DSM evolved into a service that distribution utilities offered to meet customer needs. Governments eventually saw DSM as a way of promoting energy efficiency, and regulatory systems were put in place that required an integrated resource planning (IRP) approach to capacity expansion and tariff setting. This required DSM programs to be considered on an equal footing with supply options.

In the mid-1990s, the restructuring of energy markets had a major impact on DSM. As noted in the introduction, there were fewer incentives for utilities to invest in DSM and large energy users

³ This section borrows extensively from the August 2004 Pembina Report.

⁴ Note: with the current typical valuation for GHG emissions (approximately \$15/tonne), the difference between the TRC test and the Societal Cost test is minimal.

had access to lower-priced power supplies from competing sources. Since the mid 1990s, there has been a trend to find new ways of promoting DSM with regulators focusing on retail distribution utilities, and using innovative market-based incentives, financing, and regulatory tools to level the playing field between supply and DSM resources.

More fundamentally, there is still a lively debate on what role, if any, should utilities play in the promotion of DSM. Although most jurisdictions in Canada continue to expect utilities to play the primary role, some are moving to a system where utilities are only one of many potential DSM delivery agents, or where the responsibility for DSM is divorced from utilities altogether.

Note that this paper does not address the issue of the *effectiveness* of DSM programs, as that question is dealt with, albeit more broadly, in Paper Seven: *Factors Affecting the Impact of Energy Efficiency Incentives*.

2.2 DSM AND ENERGY SECTOR REGULATION

DSM mechanisms and incentives can be implemented under one of two models currently used to regulate electric and gas utilities in Canada:

- Cost-of-service (COS) regulation allows utilities to pass through those costs deemed necessary by the regulatory body to ensure an adequate level of service is provided to end users. New or adjusted costs are added to the rate base each year, and rates are set to allow the utility to make a reasonable rate of return. The cost of running DSM programs is one of the costs included each year in the setting of rates. While this is not an incentive to undertake more DSM programming, neither is it a disincentive.
- Performance-based regulation (PBR) involves establishing multi-year performance targets for manageable costs and revenues, such as operation and maintenance, wholesale power costs, quality of service, capital investment, and DSM. The aim is to encourage utilities to improve their productivity as well as make a reasonable return. An agreed upon formula can specify the planned annual growth rate of revenues and costs adjusted for inflation and productivity over the PBR period. Rates are adjusted periodically in order to reconcile the actual and allowed levels of revenue. PBR reduces micromanaging of utility operations by the regulator while at the same time providing incentives for the utility to do better over time. Some versions of PBR utilize a price cap while others involve a revenue cap. The most sophisticated versions involve various adjustments for factors within and beyond the control of the utility.⁵

⁵ Ontario Energy Board. January 5, 2007. Staff Discussion Paper on an Incentive Regulation Framework for Natural Gas Utilities. EB-2006-0209

2.3 TYPES OF DSM INCENTIVES

There are a number of ways governments and regulators can encourage utilities to undertake DSM programs. The applicability of each of these mechanisms depends, in part, on the nature of the institutional structures, as discussed in Section 3.

- Integrated Resource Planning (IRP): Requiring that investment decisions be based on full life cycle costs of supply and DSM options.
- DSM Targets: Requiring that utilities achieve a certain level of DSM savings.
- Energy Efficiency Resource Standards (EERS): A variation on targets that includes greater flexibility by using market-based trading mechanisms.⁶
- Cost Recovery: Allowing DSM program costs to be effectively recovered in rate of return and tariff calculations, and amortized over an extended period.
- Revenue Regulation: Eliminating the incentive to increase sales by having a mandatory revenue cap or by de-coupling sales from profits.
- Lost Revenue Adjustment Mechanism (LRAM): Allowing some portion of lost revenue to be recovered in the setting of rates.
- Shared Savings Mechanism (SSM): Allowing utilities to share in savings that are achieved. For example, adding an incentive if savings are over and above DSM targets, and applying penalties if the savings targets are not met.
- Export Incentives: Allowing utilities to sell excess energy in other markets that, because of regulatory constraints or other factors, are more lucrative than the home market.
- Emissions Regulations: Limiting the emissions of greenhouse gases (GHGs) or air pollutants (through prohibitions or through absolute cap and trade systems for emission permits) provides a disincentive for new electricity generation. The potential market for offset credits may also provide a revenue stream for offset-generating DSM investments.

⁶ Pembina Institute. August 2006. Successful Strategies for Energy Efficiency: A Review of Approaches in Other Jurisdictions and Recommendations for Canada.

3. INSTITUTIONAL STRUCTURES AND REGULATORY FRAMEWORKS

The institutional structures and regulatory frameworks for natural gas and electricity in British Columbia, Alberta and Ontario are summarized in Table 3.1.

3.1 BRITISH COLUMBIA^{7,8}

Natural Gas⁹

Separate players are responsible for the supply, transmission, and distribution of the gas. BC is also in the process of unbundling the distribution and marketing of the gas, although a regulated supply is also available (in regulated supply, gas commodity rates are set on regular basis based on market prices for supply and are passed on to consumers). Most of the companies operate on a commercial basis and are investor-owned. The main distribution company is Terasen Gas (now Fortis Inc.).

The development of the system and the balance between demand and supply is assured largely by the market. However, the BC Utilities Commission (BCUC) is charged with reviewing individual utility plans for meeting energy needs and for reducing demand, in accordance with its Resource Planning Guidelines. The BCUC is also charged with approving distribution rates. Current practice is to use PBRs. Distribution rates are based on calculations of both fixed and variable costs. Customer bills reflect energy commodity costs separately from energy delivery costs.

In the case of Fortis on the mainland, DSM targets are established in negotiations through the BCUC process. Funding for DSM programs is then provided for in rates, provided the investments meet TRC and RIM tests. Utilities are also compensated for lost revenues and there are provisions to share benefits from savings that exceed targets.

Electricity¹⁰

BC Hydro is a vertically integrated utility that is responsible for most of the province's supply and distribution of electricity. As a publicly-owned utility, BC Hydro has had a mandate to promote the public good as well as to generate a financial return. Since 1983, the utility has also been subject to regulatory oversight by the BCUC.

BC Hydro has overall responsibility for the development of the electricity system and the balance of demand and supply. The BCUC is charged with reviewing and approving these plans, in accordance with its Resource Planning Guidelines. The BCUC is also charged with approving

⁷ British Columbia Utilities Commission. October 1996. Revised July 11, 2002. *Understanding Utility Regulation: A Participant's Guide to the British Columbia Utilities Commission.*

⁸ British Columbia Utilities Commission. December 2003. *Resource Planning Guidelines.*

⁹ British Columbia Utilities Commission. July 29, 2003. *Terasen Gas – Multi-Year Performance-Based Rate Plan for 2004-2008.* Order.

¹⁰ British Columbia Utilities Commission. May 11, 2007. *BC Hydro and Power Authority – 2006 Integrated Electricity Plan and 2006 Long Term Acquisition Plan.* Decision.

the rates of BC Hydro and other smaller Local Distribution Companies (LDCs). Although some of the LDCs are operating under PBRs, BC Hydro continues to operate under a COS regime. In fact, BC Hydro's rates have only recently been allowed to rise, after being frozen for more than ten years. Distribution rates are based on calculation of both fixed and variable costs. Customer bills combine both energy commodity costs and energy delivery costs.

DSM targets are usually established in negotiations through the BCUC process; however the BC Government has also mandated a specific target for BC Hydro.¹¹ Funding for DSM programs is provided for in rates, provided the investments meet TRC and RIM tests (in the case of the RIM test, a threshold of 0.8 is typically applied, which allows for a small adverse impact on non-participants, provided the TRC shows an overall benefit). Some of the smaller LDCs also have access to LRAM and SSR mechanisms. BC Hydro does not have access to these mechanisms, but it does benefit through reduced costs of generation. Furthermore, as a public utility, DSM also fits within its mandate.

3.2 ALBERTA

Natural Gas¹²

Separate players are responsible for the supply, transmission, distribution and marketing of the gas. Companies operate on a commercial basis and most are investor-owned. The main LDCs are ATCO Gas and AltaGas. There are a variety of retailers, including AltaGas, Direct Energy, and ENMAX.

The development of the system and the balance between demand and supply is market-driven. The Alberta Energy and Utilities Board (AEUB) is responsible for approving distribution rates, which are based on a COS approach. Distribution rates are based on calculations of both fixed and variable costs. Customer bills reflect energy commodity costs separately from energy delivery costs.

Climate Change Central has an overall mandate to promote the development of innovative responses to climate change (including energy efficiency); however, there is no mechanism to establish formal DSM targets. The AEUB considers DSM to be a retailer service as opposed to a utility service (since the retailer is has the customer contact). There is no rate-based funding for DSM programs; however some retailers and utilities offer programs that leverage federal or provincial funding. In some cases, Climate Change Central plays a role in facilitating these investments. There are no LRAM or SSM mechanisms.

Electricity^{13,14,15}

¹¹ It is not yet clear, how the BCUC will treat the Government-mandated target in its approval processes.

¹² Alberta Energy and Utilities Board. November 2006. Frequently Asked Questions on the Development of Alberta's Energy Resources. EnerFAQs No.11.

¹³ Alberta Energy and Utilities Board. November 2006. Frequently Asked Questions on the Development of Alberta's Energy Resources. EnerFAQs No.7.

¹⁴ Clean Air Strategic Alliance. October 2003. Report of the Energy Efficiency and Conservation Working Group to the CASA Electricity Project Team.

¹⁵ Pembina Institute. March 2001. A Smart Electricity Policy for Alberta. Enhancing the Alberta Advantage.

As for natural gas, separate players are responsible for the supply, transmission, distribution and retailing of electricity. Companies operate on a commercial basis and most are investor-owned. The main LDCs are Fortis Alberta, ATCO Electric, EPCOR and Enmax.

The Alberta Electric System Operator is responsible for forecasting demand and for planning for transmission however, the development of the system and the balance between demand and supply is market-driven. The Alberta Energy and Utilities Board (AEUB) is responsible for approving distribution rates, which are based on a COS approach. Distribution rates are based on calculations of both fixed and variable costs. Customer bills reflect energy commodity costs separately from energy delivery costs. Some bills combine fixed and variable costs, some list transmission and distribution separately.

The DSM situation is the same as for natural gas. Climate Change Central has an overall mandate to promote responses to climate change but there is no mechanism to establish formal DSM targets.¹⁶ There is no rate-based funding for DSM programs; however some retailers and utilities offer programs that leverage federal or provincial funding. In some cases, Climate Change Central plays a role in facilitating these investments. There are no LRAM or SSM mechanisms.

3.3 ONTARIO

Natural Gas^{17,18,19}

Separate players are responsible for the supply, transmission, distribution, and marketing of the gas. Most of the companies operate on a commercial basis and are investor-owned. The main distribution companies are Enbridge and Union. Gas may be purchased from marketers (fixed price for set period) or through utilities under a regulated (variable) price.

The development of the system and the balance between demand and supply is market-driven. The Ontario Energy Board (OEB) is responsible for approving distribution rates. Current practice is to use COS, however the OEB is proposing to move to 4-5 year PBR approach. Distribution rates are based on calculations of both fixed and variable costs. Customer bills reflect energy commodity costs separately from energy delivery costs and fixed costs separately from variable costs.

DSM targets are established in negotiations through the OEB process. Funding for DSM programs is then provided for in rates; provided the investments the TRC test (other tests may also be used to prioritize the choice of programs). Utilities are also compensated for lost revenues and there are provisions to share benefits from savings that exceed targets. There are

¹⁶ Following up on its 2003 Report, the Clean Air Strategic Alliance (CASA) attempted to develop energy efficiency targets for electricity but was unable to do so without a clear policy framework for energy efficiency from the Government of Alberta.

¹⁷ Ontario Energy Board. March 30, 2005. Natural Gas Regulations in Ontario: A Renewed Policy Framework. Report on the Ontario Energy Board Natural Gas Forum.

¹⁸ Ontario Energy Board. August 25, 2006. *Decision with Reasons*. EB-2006-0021

¹⁹ Ontario Energy Board. January 5, 2007. Staff Discussion Paper On an Incentive Regulation Framework for Natural Gas Utilities. EB-2006-0209

also provisions to support investments in market transformation initiatives and to require minimum spending on low-income customers.

Electricity^{20,21}

Separate players are responsible for the supply, transmission, distribution, and retailing of electricity. Companies operate on a commercial basis and most are publicly-owned (Ontario Power Generation and Hydro One are owned by the Province; and the distribution companies are owned mainly by municipalities). The main distribution companies are Toronto Hydro, Hydro Ottawa, Enersource Hydro Mississauga, PowerStream and Veridian Connections. Electricity may be purchased from retailers (fixed price for set period) or through utilities under a regulated (variable) price.

For a transitional period (until the market is able to function adequately), the development of the system and the balance between demand and supply is the responsibility of the Ontario Power Authority (OPA). The OPA is also responsible for the promotion of conservation and of DSM programs. The OEB is responsible for approving distribution rates. Current practice is to use PBR, however the OEB is also working on the development of a new "third generation" PBR approach that will deal more comprehensively with rate-making incentives. Distribution rates are currently based on calculations of both fixed and variable costs, but there is no clear basis for the allocation of these costs in the rates. Customer bills reflect energy commodity costs separately from energy delivery costs, however the simplified bill combines the fixed costs and variable costs for delivery.

Specific and time-bound DSM targets have been mandated by the government to the OPA, with funding to come from a global commodity cost adjustment. The OPA is beginning to roll-out DSM programs using a variety of delivery agents, including \$400 million for an LDC fund (expected to be approximately one third of total DSM spending over the period 2007-2010). In the meantime, the OEB also provides rate-based funding for utility DSM programs for programs where OPA funding is not (or not yet) available. Both the OPA and the OEB use the TRC test to assess programs. LRAM is available to utilities for programs funded by the OEB or the OPA, but not for third party programs. SSM is available for rate-based programs but not for OPA programs. Instead, the OPA builds incentive mechanisms into its contracts with LDCs.

²⁰ Ontario Energy Board. March 2, 2007. Report of the Board on the Regulatory Framework for Conservation and Demand Management by Ontario Electricity Distributors in 2007 and Beyond. EB-2006-0266.

²¹ Ontario Energy Board. March 30, 2007. Staff Discussion Paper. Rate Design for Electricity Distributors: Overview and Scoping. EB-2007-0031

Table 3.1
Institutional Structures and Regulatory Frameworks for Energy Utilities - Selected Jurisdictions in Canada

Aspect	British Columbia		Alberta		Ontario	
	N. Gas	Electricity	N. Gas	Electricity	N. Gas	Electricity
Structure of system	Separate players for supply, transmission, distribution, marketing	Vertically-integrated (BC Hydro), except transmission	Separate players for supply, transmission, distribution, marketing	Separate players for supply, transmission, distribution, retailing	Separate players for supply, transmission, distribution, marketing	Separate players for supply, transmission, distribution, retailing
Ownership of Distribution Utilities	Commercial, largely privately-owned	Public (BC Hydro)	Commercial, largely privately-owned	Commercial, largely privately-owned	Commercial, largely privately-owned	Commercial, largely publicly-owned
Retail Market Access	Open (default regulated rate also applies)	No	Open	Open (default regulated rate also applies)	Open (default regulated rate also applies)	Open (default regulated rate also applies)
Responsibility for System Planning	N/A, market driven – but Resource Planning Guidelines enforced by BCUC	BC Hydro – also guided by Resource Planning Guidelines	N/A, market driven, Climate Change Central is a main player in facilitating investments in energy efficiency	Market driven (AESO provides load forecasting and transmission planning), Climate Change Central is a main player in facilitating investments in energy efficiency	N/A, market driven	OPA (transitional body)

Aspect	British Columbia		Alberta		Ontario	
	N. Gas	Electricity	N. Gas	Electricity	N. Gas	Electricity
Rate Basis	PBR (up to four years)	Rates frozen from 1993-2004, since then COS – interest in moving to PBR but latest BC Hydro application continues COS approach	Cost of Service (COS)	Cost of Service (COS)	Cost of Service (COS) but moving towards a 4-5 year performance based incentive regulation (PBR)	Incentive rate-making (fixed for up to 3 years) – A third generation PBR is in development
Rate design	Both fixed and variable – information on allocation not available	Both fixed and variable – information on allocation not available	Both fixed and variable – fixed costs include customer costs and overhead and some parts of system installation.	Both fixed and variable – fixed costs include customer costs and overhead and some parts of system installation.	Both fixed and variable – fixed costs include customer costs and overhead and some parts of system installation and maintenance	Both fixed and variable but no clear basis for allocation
Variable Billing Determinant	GJ	kWh (small) kW (larger)	GJ	kWh (small) kW or kVA (larger)	m ³	kWh (small) kW or kVA (larger)

Aspect	British Columbia		Alberta		Ontario	
	N. Gas	Electricity	N. Gas	Electricity	N. Gas	Electricity
Consumer Bill	Energy and delivery are separate. Both fixed and variable charges are listed	Both fixed and variable charges. Energy and delivery cost are combined.	Energy and delivery are separate. Both fixed and variable charges are listed	Energy and delivery are separate. Bills vary: some combine fixed and variable; some combine transmission and distribution	Energy and delivery are separate. Some bills combine transportation, storage, delivery (but fixed monthly fee is separate)	Energy and delivery are separate. Simplified bill: single charge for delivery (incl. fixed and variable)
DSM Targets	Targets negotiated as part of BCUC process – taking into account Resource Planning Guidelines	Targets negotiated as part of BCUC process – taking into account Resource Planning Guidelines	No	No	Targets for each utility are negotiated as part of OEB process	Government Directive setting demand reduction targets to OPA for 2007, 2010 and 2025
Funding for DSM Programs (non rate-based) ²²	N/A	N/A	Individual players Market-driven Climate Change Central has a facilitator role	Individual players Market-driven Climate Change Central has a facilitator role	N/A	Funded through commodity Global Adj. Mechanism - through OPA (2007-2010)
Rate-Based Funding for DSM Programs	Yes	Yes	No	No	Yes, 3 year plan at levels fixed by the OEB	Yes, if not available from OPA
Funding Test	TRC and RIM	TRC and RIM	N/A	N/A	TRC – other tests may be used to prioritize	TRC

²² Note: Federal Government is also a major funding source in all jurisdictions.

Aspect	British Columbia		Alberta		Ontario	
	N. Gas	Electricity	N. Gas	Electricity	N. Gas	Electricity
Lost Revenue Adjustment Mechanism (LRAM)	Yes, part of Revenue Stabilization Adjustment Mechanism (RSAM)	Has been used for Fortis BC but not in place for BC Hydro	No	No	Yes	Yes, for rate-based or OPA Distributor Fund but not third parties
Shared Saving Mechanism (SSM)	Yes	Used for Fortis BC (escalating incentive or penalty based on target) but not for BC Hydro	No	No	Yes, escalating scale % of TRC up to a cap	Yes, only if rate-based (5% of TRC) – Otherwise incentives are part of OPA contracts with utility
Other Features		As a vertically integrated and publicly-owned utility, BC Hydro has other incentives that offset lost revenues			Rate-Based Funding and Incentives for Market Transformation Initiatives	
					Minimum spending on low-income customers	

4. BARRIERS AND OPPORTUNITIES

In recent years, governments and regulators have taken steps to remove or mitigate many of the institutional and regulatory barriers to DSM. However, several barriers remain and, as described above, the situation varies by jurisdiction. Some of the main barriers are described below, along with opportunities to overcome them.

Loss of Revenues

- **Barrier.** This is the most fundamental barrier. To the extent that utility revenues and profits are tied to the sale of the energy commodity, there will be a clear disincentive for them to undertake DSM programs. In an unbundled ("wires only") distribution utility, the impact of a 5% reduction in sales on after-tax earnings can reach 45-50%.²³ In a vertically-integrated utility, the loss in revenues may be offset by reduced power production or purchase expenses, but even there, the same reduction in sales can reduce earnings by 20-25%. For a publicly-owned utility, the loss in revenues may be considered an acceptable trade-off for the public good, but over the long run, the impact on the Treasury is likely to erode the willingness of elected officials to support such losses.
- **Opportunities.** Potential avenues to overcome this barrier include: relying on other delivery agents for DSM (e.g. OPA or Climate Change Central); adopting adjustment mechanisms for lost revenues (e.g. LRAM); or more fundamentally, decoupling revenues from sales by allowing a set revenue per customer or a return on capital assets (in BC, it is said that some utilities make money by selling GJ while others make money by building assets). It should be noted that decoupling utility revenues from sales does not mean decoupling customer payments from consumption (even for delivery services) nor does it mean fixing utility earnings and capping the upside potential for utilities. Decoupling can be combined with a sliding scale or range of earnings potential that rewards increasing efficiency. Such fundamental changes are expected to be considered as part of the process to develop Ontario's 3rd generation Incentive Rate Making and some aspects are included in natural gas PBRs in Ontario and BC.

Inertia

- **Barrier.** Even when there is no strong disincentive, the lack of an additional positive incentive may preclude the development of a compelling business case for DSM rather than other investments. This is particularly true if the costs are substantial. Even if costs can be recovered, the case for DSM will suffer if there are no benefits to outweigh the risks. In part, this may be due to lack of senior management awareness or interest, and to an implicitly higher risk premium on DSM investments than on other investments.
- **Opportunities.** To overcome this barrier, the options are: to provide funding for DSM; to compel investment in DSM through resource planning direction (e.g. BCUC), DSM targets or Energy Efficiency Resource Standards (EERS); and/or to introduce mechanisms to share the TRC benefits between society and the DSM program agent

23 Source: the Regulatory Assistance project (www.raponline.org). The magnified effect on earnings is due to the fact that there is typically little associated reduction in expenses.

using SSM (e.g. OEB and BCUC). SSMs can be designed to act in concert with energy efficiency resource standards or DSM targets, rewarding performance that exceeds targets, and penalizing poor performance. In Ontario, OPA-funded programs will not be eligible for SSM, and so it will be necessary for the OPA to design other effective mechanisms to reward utilities that achieve or exceed targets.

Impacts on Distribution Rates

- **Barrier.** The recovery of DSM costs, the compensation for lost revenues and the sharing of TRC benefits may be done through utility rates. The consequence is that rates will go up (even if costs come down for most customers). In many cases, this may be opposed by various groups of rate payers whose primary interest is to keep rates as low as possible (this is linked to the issue of rate class equity – see below). As rate-making is often a process of balancing these interests and negotiating an acceptable settlement, regulators may be under pressure to reduce the amount of DSM investment. Part of the problem may be that many stakeholders are focused on rates, when they should be focused on costs (which may be lower despite higher rates, thanks to energy efficiency).
- **Opportunities.** One option to overcome this barrier is to promote greater awareness of the benefits of DSM programs on energy costs. Another possibility is to find broader sources of revenue for DSM programming (other than distribution rates). For example, province-wide system benefit funds can be established from a charge on the energy commodity itself rather than on its delivery (e.g. through the Global Adjustment Mechanism in Ontario, or from BC Hydro's broad revenue base). Alternatively, given the societal benefits, DSM programming could be funded from the tax-base. Theoretically, one could consider a hybrid approach, however this would need to be designed and communicated carefully to avoid the impression of customers paying twice for DSM.

Administration and Transaction Costs

- **Barrier.** The process of assessing DSM potential, selecting and designing DSM programs, obtaining approvals, monitoring, evaluating and reporting is costly and time consuming. Although most of these costs may be recoverable through the mechanisms described above, they can demand investment of substantial intellectual and management capital, which all utilities (and smaller utilities in particular) have in short supply.²⁴ The reality is that each organization will only be able to invest in a select number of initiatives. Furthermore, cases such as Ontario where there are some 100 electric utilities, there may be some duplication of effort. This means that much of the available potential may not be realized.
- **Opportunities.** Some of the approaches to overcome this barrier include: the development of information-sharing networks (e.g. in Ontario, the Coalition of Large Distributors shares information on programs) and clearinghouses; and/or the creation of separate agencies (e.g. OPA, Climate Change Central) to realize economies of scale and coordinate design of "programs in a box" that can be delivered by many utilities.

²⁴ For example, in Ontario, the process for obtaining LRAM and SSR may require OEB hearings with intervenors. Some utilities may not consider it worthwhile to engage in the process if the potential return is not large.

Regulators and others can also play a role in streamlining the process by publishing guides and standards (e.g. the TRC Guide in Ontario, Resource Planning Guidelines in BC), by simplifying approval and reporting requirements for smaller or more routine programs, and by providing flexibility in the regulatory framework (e.g. allowing utilities to reallocate funds between DSM programs, provided certain conditions are met).

Uncertainty and Lack of Consistency

- **Barrier.** As noted above, the development of DSM programming requires the investment of substantial infrastructure and intellectual capacity. This infrastructure and specialized capacity cannot be created overnight. It must be developed and nurtured over time. To recruit and retain the right individuals, it is important that utilities and other players have the assurance that they can plan for the long term. This is an important consideration as policies evolve and plans change. For example, in BC, DSM capacity suffered extensively when funding went from more than \$60 million per year in the mid-1990s, to zero in 2001, back to \$60 million in 2005.²⁵ In Ontario, the creation of the OPA and the decision to fund DSM centrally has had a variety of benefits. However, the uncertainty surrounding the transitional nature of the Agency, the limited length of the allocated funding, and the delays faced in rolling out programs (due in part to the staffing constraints that the Agency itself faces) creates problems for utilities. In some cases, the uncertainty is leading to the loss of staff, experience, expertise and momentum gained through several years of rate-based DSM programming.
- **Opportunities.** To overcome these problems, governments may need to establish longer term targets and accept longer term commitments, remove artificial barriers on staffing, and/or provide alternative avenues for utilities to establish long-term, predictable and secure funding.

Knowledge of customers and local conditions

- **Barrier.** As noted above, one option for dealing with the disincentives for utility DSM is to rely on other organizations to deliver DSM. To some extent, all jurisdictions rely on this approach already through the implementation of various federal and provincial programs and the actions of a variety of players, including Energy Service Companies and Industry Associations. In Ontario, a hybrid system is developing where the OPA provides a central role but LDCs have a major role in program delivery, and a variety of other players also contribute. In Alberta, distribution companies and energy retailers have only played a limited role in DSM and neither has a clear mandate to do so. While players other than utilities can deliver substantial energy efficiency benefits, the experience to date suggests that, without the involvement of the companies that have the most direct relationship with energy customers, the ability to target programs, to monitor outcomes, and to adjust program delivery will be less than ideal.
- **Opportunities.** To overcome this barrier, it may be appropriate to rely on a mix of approaches and several DSM Champions. In some jurisdictions (e.g. Ontario) this may include LDCs, whereas in other jurisdictions (e.g. Alberta), energy retailers may be better suited to filling this role.

²⁵ Pembina Institute. August 2006. Successful Strategies for Energy Efficiency: A Review of Approaches in Other Jurisdictions and Recommendations for Canada.

Rate Class Equity

- **Barrier.** In addition to the general concern about rate increases, some stakeholders may also be concerned about specific inequities affecting particular classes of ratepayers such as low-income customers. The concern is that these customers may have to pay higher rates for programs that they can not access. One measure of this effect is the RIM test, or non-participant test. In some jurisdictions (e.g. BC), proposed DSM programs must be able to demonstrate, in addition to an overall benefit, that the cost-benefit for non-participants is not excessive (e.g. that the ratio of benefits to costs is at least 0.8). In practice, other jurisdictions also consider the RIM test and are unlikely to proceed with programs have significant negative impacts for non-participants. The result is that DSM investments which are beneficial from a societal perspective may not proceed.
- **Opportunities.** To overcome this barrier, it may be necessary to ensure that a fair share of DSM investments is targeted to each class of customer (this may need to be done even though other opportunities with better TRC ratios are available elsewhere). In particular, the significant potential for energy savings from low-income customers should be investigated more carefully (see accompanying paper on energy affordability). Alternatively, it may be necessary to consider other ways of compensating non-participants.

Lack of Value Assigned to Adverse Externalities

- **Barrier.** As noted in Section 3, most jurisdictions rely on the TRC test to assess the costs and benefits of DSM. Because the TRC test does not value adverse externalities (e.g. air emissions, health impacts, and climate change), the full range of DSM opportunities are not being realized.
- **Opportunity.** The best way to overcome this barrier is for governments to include externalities in the price of commodities, upstream of distribution and retail. Otherwise, the Societal Cost test could be used. However, as noted the difference may be small if including only the traditional valuation for GHGs. Thus a broader valuation of externalities (i.e. including other emissions and environmental/health impacts) may be appropriate.²⁶ In the context of electricity emissions, one of the key considerations is the choice of the appropriate source of alternative supply. General practice is to consider the marginal source of electricity, however this leaves open the question of using "operating marginal" (typically a natural gas plant) or "build marginal" (which can be almost anything). In cases where the DSM savings are relatively small, it may be more appropriate to consider the "operating marginal" source of electricity. Note that the non-energy benefits of energy efficiency (e.g. improved economic competitiveness, employment, energy security) could also be added to the equation.

Lack of Value Assigned to Market Transformation Benefits

- **Barrier.** In addition to providing a valuable resource, DSM programs can play a crucial role in paving the way towards market transformation. Such programs often provide a link between early market adoption, consumer acceptance and the eventual imposition of

²⁶ This approach is controversial as some argue that it is up to governments to assign value to environmental externalities (through taxation if necessary) and that utility regulators should stick to monetized costs.

minimum energy performance standards. In so doing, they provide the market and the public with the experience necessary for government regulation to become feasible.

- **Opportunity.** It is unlikely that these benefits can be monetized at this stage, however, it may be possible for governments to consider them qualitatively in their decision-making processes.

Lost Opportunities

- **Barrier.** Assuming that mechanisms are in place to overcome the key barriers identified above, there will be appropriate incentives to seek out the most cost-effective DSM opportunities. In capturing these opportunities, there may be occasions where other less cost-effective opportunities become lost or stranded because they don't meet the regulatory economic hurdles. The problem may be that the incentives lead utilities to "skim the cream".
- **Opportunity.** To overcome this barrier, it is important to encourage a long term view and adjust incentives so that utilities are not penalized for proactive planning and are rewarded for developing "packages" that realize the full potential of the available DSM opportunities.

Narrow Focus

- **Barrier.** If natural gas and electricity utilities focus exclusively on end-use efficiency, they may neglect other system efficiency opportunities such as switching heating and hot water applications from electricity to natural gas, if the gas offers a full-cycle (production, transmission, distribution and end-use) advantage. Similarly, opportunities for switching to renewable sources of energy (e.g. solar hot water) may also be missed.
- **Opportunity.** To overcome this barrier, regulators and/or central agencies need to be open to a broader systems perspective in assessing DSM proposals. They should also be open to receiving business cases for programs that target multiple energy sources (e.g. electricity, gas, or renewables). This could be delivered by any of the existing utilities or by a third party.

Lack of policy alignment

- **Barrier.** In most situations, energy and economic policy objectives will align with environmental objectives, however, there are cases where they may not. For example, it may make sense from an efficiency perspective to promote fuel switching from electricity to natural gas for heating and hot water, however, in jurisdictions with access to low-carbon electricity sources there may be a concern about increased GHG emissions.
- **Opportunity.** To overcome this barrier, it is necessary for jurisdictions to take an even broader perspective and consider that the low-carbon electricity could be used to displace higher-carbon electricity in other nearby jurisdictions.

Policy Disconnect

- **Barrier.** In most situations, provincial priorities and direction given to regulators are aligned (a good example is BC's energy plan) and this allows for a holistic approach to energy efficiency. In other cases there may be a disconnect between provincial priorities, energy policy and regulatory direction which creates complex processes and long lag

times for utilities to receive regulatory approval for EE/DSM plans even when energy conservation has been identified as a priority for the province.

- **Opportunity.** To overcome this barrier, it is necessary to ensure that provincial energy priorities are reflected in all aspects of energy regulation and delivery.

Jurisdiction

- **Barrier.** As noted previously, energy is an area of provincial jurisdiction. Each province has developed its own approach and thus the opportunities for a consistent national approach to utility DSM regulation are limited.
- **Opportunity.** Nonetheless, the federal government could play a facilitation role by collaborating with the provinces in researching and documenting the opportunities, by disseminating best practices, and by providing common information base on DSM policy and programming lessons for use by utilities, regulators, and provincial governments. The recent publication of the Council of Energy Ministers Report: *Moving Forward on Energy Efficiency in Canada: A Foundation for Action* provides a basis for such collaborative actions. The ADM Steering Committee on Energy Efficiency's mandate is to establish a coordinated and complementary agenda for energy efficiency (EE) in Canada within the context of the Council of Energy Ministers (CEM) dialogue. The objective is to work towards significantly increasing the contribution of energy efficiency within each jurisdiction, through sharing of information, resources, and program design and policy frameworks. The primary role is to facilitate the discussion aimed at a long-term, coordinated approach to accelerating both energy efficiency and demand-side management (DSM) in Canada.

5. FURTHER EXPLORATION

It is beyond the scope of this paper to analyze in detail the effectiveness of different types of DSM incentives, however, it would be useful to consider and contrast each of the mechanism in relation to factors such as: maximization of energy savings, minimization of ratepayer (or taxpayer) costs, administrative simplicity, reliance on market forces, etc.

Similarly, it is beyond the scope to examine the strengths and weaknesses of the various potential delivery agents or combination of agents for DSM programs (e.g. LDCs, governments, third-parties), however, it would be helpful to do that and attempt to identify which agents are best suited to meet customer expectation with respect to specific types of programs or market segments.

Finally, it would also be worth examining the experience of other jurisdictions, including jurisdictions in Canada (e.g. Québec) and internationally (e.g. California and the U.K.).

6. KEY MESSAGES

- The ability to reduce energy demand offers benefits to customers, utilities and society as a whole that are masked by a variety of institutional and regulatory barriers. Overcoming these barriers provides access to a resource that can cost-effectively compete with supply options.
- There are a variety of approaches that jurisdictions can use to promote investment in DSM programs. In most cases, there are appropriate roles for governments, central agencies, and either utilities or retailers.
- Utilities require a mechanism to fund the programs, in order to compensate for lost revenue and to reward performance.
- A variety of funding sources should be considered, including global commodity charges, distribution rates, and/or funding from the broader tax base.
- A broad measure of cost effectiveness should be used (including TRC and possibly incorporating externalities). However the selection of DSM programs should also consider impacts on various classes of ratepayers.
- Regulators and central agencies need to provide incentives to avoid lost opportunities and develop packages of cost-effective actions.
- Regulators and central agencies should adopt a broad, system-based outlook on DSM opportunities.
- Government and regulators should ensure that all ratepayers have access to the benefits of DSM programs.
- The Federal government could facilitate the realization of DSM opportunities by working with provinces to disseminate best practices and to use their resources to encourage the efficient use of energy in support of provincial priorities.

7. APPENDIX A; GLOSSARY OF DSM TERMS

Cost-of-Service (COS) Regulation	Regulatory approach that allows utilities to pass through those costs deemed necessary by the regulatory body to ensure an adequate level of service is provided to end users. New or adjusted costs are added to the rate base each year, and rates are set to allow the utility to make a reasonable rate of return.
Cost Recovery	Mechanism that allows DSM program costs to be effectively recovered in cost of service and tariff calculations, and amortized over an extended period.
Demand Side Management (DSM)	Measures to promote conservation behaviour, energy efficiency, demand-management, fuel-switching, and self-generation.
Energy Efficiency Resource Standards (EERS)	A variation on targets that includes greater flexibility by using market-based trading mechanisms.
Export Incentive	Policy that allows utilities to sell excess energy in other markets that, because of regulatory constraints or other factors, are more lucrative than the home market.
Integrated Resource Planning (IRP)	Approach that bases investment decisions on full life cycle costs of supply and DSM options.
Lost Revenue Adjustment Mechanism (LRAM):	Mechanism that allows some portion of lost revenue to be recovered in the setting of rates.
Performance-Based Regulation (PBR)	Regulatory approach that involves establishing multi-year performance targets for manageable costs and revenues, such as operation and maintenance, wholesale power costs, quality of service, capital investment, and DSM. The aim is to encourage utilities to improve their productivity as well as make a reasonable return. An agreed upon formula can specify the planned annual growth rate of revenues and costs adjusted for inflation and productivity over the PBR period. Rates are adjusted periodically in order to reconcile the actual and allowed levels of revenue.
Ratepayer Impact Measure (RIM) Test	Calculation that measures the impact of a DSM program on customer billing rates due to changes in utility revenues and operating costs. This may also be referred to as the non-participant test and is a

	measure of fairness.
Revenue Regulation:	Regulatory approach that eliminates the incentive to increase sales by having a mandatory revenue cap or by de-coupling sales from profits.
Shared Savings Mechanism (SSM):	Mechanism that allows utilities to share in savings that are achieved. For example, adding an incentive if savings are over and above DSM targets, and applying penalties if the savings targets are not met.
Societal Cost Test	Calculation similar to the TRC test, but includes a monetized value for the impact of a DSM program on emission reductions.
Total Resource Cost (TRC) Test	Calculation that measures the net benefits of a DSM program as a resource option based on the supply side benefits and the total costs of the program, including costs to consumers and to utilities.
Utilities Cost (UC) Test	Calculation that measures the change in utility costs and revenues.

8. APPENDIX B; ACRONYMS

Alberta Energy and Utilities Board	AEUB
BC Utilities Commission	BCUC
Clean Air Strategic Alliance	CASA
Council of Energy Ministers	CEM
Cost-of-service	COS
Demand-Side Management	DSM
Energy efficiency	EE
Energy Efficiency Resource Standards	EERS
Greenhouse gases	GHGs
Gigajoule	GJ
Integrated resource planning	IRP
Kilovolt-ampere	kVA
Local Distribution Companies	LDCs
Lost Revenue Adjustment Mechanism	LRAM
Ontario Energy Board	OEB
Ontario Power Authority	OPA
Performance-based regulation	PBR
Ratepayer Impact Measure	RIM
Revenue Stabilization Adjustment Mechanism	RSAM
Shared Savings Mechanism	SSM
Total Resource Cost	TRC
Utilities Cost	UC