Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
26th Floor
Toronto, ON M4P 1E4
Telephone: (416)481-1967
Facimile: (416)4407656

Commission de l'Énergie de l'Ontario
C.P. 2319
2300, Rue Yonge
26e étage
Toronto, ON M4P 1E4
Téléphone: (416)481-1967
Télécopieur: (416)4407656

Ontario Energy Board Staff Discussion Paper

Demand-Side Management and Demand Response in the Ontario Energy Sectors

October 6, 2003

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1 BACKGROUND AND PAPER OVERVIEW

1.1 Background

The Minister's Directive to the Board to consult with stakeholders on delivery of DSM and DR in the electricity sector

The Board received a directive from the Minister of Energy under Section 27.1 of the *Ontario Energy Board Act, 1998* (OEB Act) on June 18, 2003 (the Directive). In it, the Minister directed the Board to consult with stakeholders to identify and review options for the delivery of demand-side management (DSM) and demand response (DR) activities within the electricity sector, including the role of the local distribution company (distributor) in such activities. The Directive includes reference to the potential role for load aggregators within the Independent Electricity Market Operator's (IMO's) administered markets. The Directive asks the Board to balance implementation costs with the benefits to both consumers and to the entire system. The Board is to report back to the Minister with its analysis and recommendations for both the short and long term by March 1, 2004.

Government Task Force

The Government also appointed a task force, the Electricity Conservation and Supply Task Force, to provide an action plan outlining ways to attract new generation and identifying mechanisms for DSM. Work of this task force will parallel the Board's consultations.

Examination to include role of gas distributors

On August 8, 2003, the Board announced its plan to expand the scope of the review concerning the Minister's June 18, 2003 directive to include the role of gas distributors in DSM.[1]

Power emergency shows potential for DSM and DR

A recent example of the importance of this subject is apparent from the success of efforts by large and small consumers in response to the recent power emergency shows the potential for DSM and DR. This potential needs to be organized as a predictable resource.

1.2 Scope

Principles, not programs

The role of the distributor will be examined within the broader work to fulfill the Minister's Directive

The scope of the Board's examination will include DSM and DR activities in both wholesale and retail markets, and the role of the distributor. While specific programs may be examined to understand options and demonstrate principles, the level of analysis and recommendations will be directed toward principles, not programs. The recommendations to the Minister will describe the policy framework needed to implement the various options for DSM and DR in the Ontario electricity sector, including any necessary changes in market design, legislation, market rules, licensing, codes, rates, etc.

The role of the distributor in the gas sector

The examination will also consider how this framework can be appropriately applied to the role of the distributor in the natural gas sector.

The Board may implement any matters within its jurisdiction.

1.3 Overview of this Paper

Purpose of this paper

The purpose of this paper is to present preliminary research and ideas to the reader on DSM and DR. It is intended to form the basis of, and provide a framework for discussion, without drawing conclusions.

Structure of the paper

Chapter 2 suggests definitions of DSM and DR for the purposes of discussion, including a brief discussion of economic theory and competitive markets. Chapter 3 presents a framework for discussion, including a list of issues and other considerations. Chapters 4 and 5 present a spectrum of potential approaches to a DSM and DR framework, respectively, with jurisdictional examples. Chapter 6 provides a brief overview of the concept of load aggregation. Chapter 7 outlines the next steps in consultations.

The Appendices include an overview of the electricity and gas sectors, a history of DSM in Ontario, a summary of the role of electricity distributors in various jurisdictions, references, and a glossary of terms and acronyms.

2 OVERVIEW OF DSM AND DR

DSM and DR describe activities that are designed to moderate demand for energy and/or power, which demand would otherwise have to be met with increased supply. Within this broad definition, DSM and DR can have many objectives, including least cost planning by reducing demand on the system, resource conservation, emission reduction, consumer bill reduction, etc.

DSM and DR are separate but related concepts

DSM and DR are separate but related concepts. They both require some sort of informed-choice of action by a consumer related to their consumption of energy. In the case of DSM, the action is often influenced through incentive programs offered by an energy company (e.g., energy services, retailer, generator, distributor, etc) and/or personal preference, and results in a sustained reduction in energy use. In the case of DR, consumer action is influenced by market prices, and generally results in a temporary reduction in energy use. There are also actions that fall between DSM and DR in that they use financial incentives to encourage consumers not to

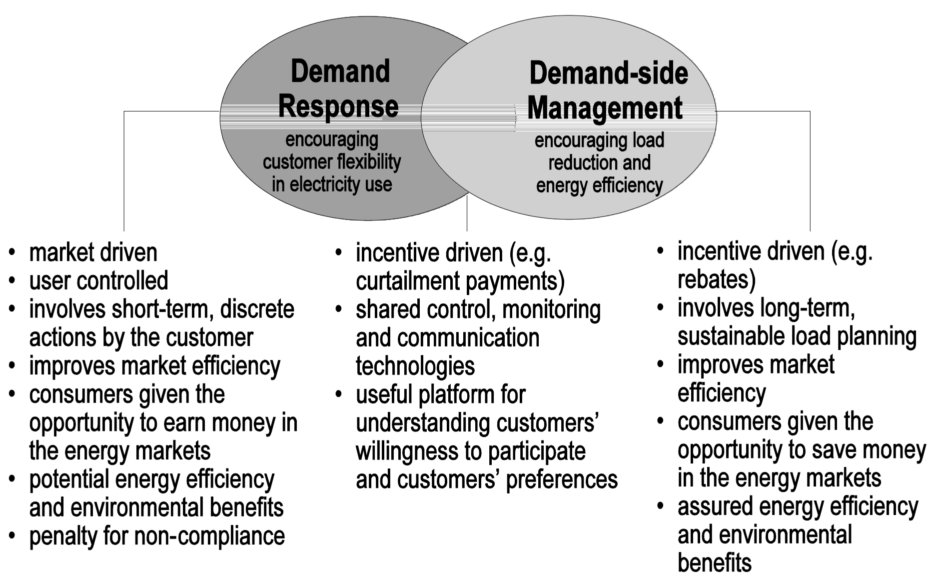

Figure 2: Some Elements of DSM and DR

consume energy (like DSM) at peak periods, and result in temporary reductions in energy use (like DR). Some elements of DSM and DR are illustrated in Figure 2.

This discussion paper considers DSM and DR separately.

2.1 What is DSM?

The Board's July 23, 2003 *E.B.O. 169-III Report of the Board* defined DSM as "actions taken by a utility or other agency which are expected to influence the amount or timing of a customer's energy consumption." The Ontario Market Design Committee's *Final Report of the Market Design Committee To the Honourable Jim Wilson, Minister of Energy, Science and Technology*, dated January 29, 1999, defined DSM as "measures undertaken to control the level of energy usage at a given time, by increasing or decreasing consumption or shifting consumption to some other time period. DSM efforts can be undertaken by consumers, utilities or third parties."

Definition of DSM for this paper

For the purposes of this paper, DSM means actions taken by an energy utility, retailer, or services company which are designed to influence the amount or timing of a consumer's energy consumption. Actions may be designed to increase energy efficiency, encourage energy conservation or implement load management.

DSM programs, either as part of an integrated resource plan (IRP) or on their own, are generally pursued as a load management tool to modify consumer load profiles. They may have specific capacity targets associated with specific times or locations on the system. Such programs have a variety of objectives: energy efficiency programs reduce total energy use; load reduction programs focus on reducing load during periods of peak power consumption; load building programs increase electrical load in off-peak hours; and, load shape programs shift electricity consumption from peak to off-peak hours through modifying prices, cycling equipment, or interrupting service.

2.2 What is DR?

Definition of DR for this paper

For the purposes of this paper, DR means actions voluntarily taken by a consumer to adjust the amount or timing of his energy consumption. Actions are generally in response to an economic signal (e.g., energy price, or government and/or utility incentive).

DR less significant in gas sector

DR is a less significant issue in natural gas than in electricity, since the ability to store natural gas means that production and end use do not need to be in constant balance.

DR actions take the form of price response, demand bidding or voluntary load shedding.

While not an exhaustive list, some examples of DSM and/or DR activities may include:

- provision of information (e.g., energy audits, fact sheets);
- replacement of equipment (e.g. insulation, windows, appliances and equipment, lighting, heating and air conditioning, water heating);
- building design (e.g., including energy efficient equipment and building standards, and small-scale generation including solar heating and cooling, photovoltaics, passive solar design, and/or day lighting); and

- load control (e.g., appliance timers and controllers, time-of-use, interruptible rates).

2.3 Economic Theory and Competitive Markets

Economic theory

The "demand and supply" theory of commodity markets forms the basis of the market design principles to Ontario's competitive electricity market. In an ideal market, suppliers are willing to increase (decrease) supply in response to higher (lower) prices while consumers increase (decrease) their demand as prices fall (rise). As illustrated in Figure 3, a market equilibrium is reached when the quantity of power that suppliers are willing to provide at the prevailing market price is the same as the quantity that customers are willing to consume at that price.

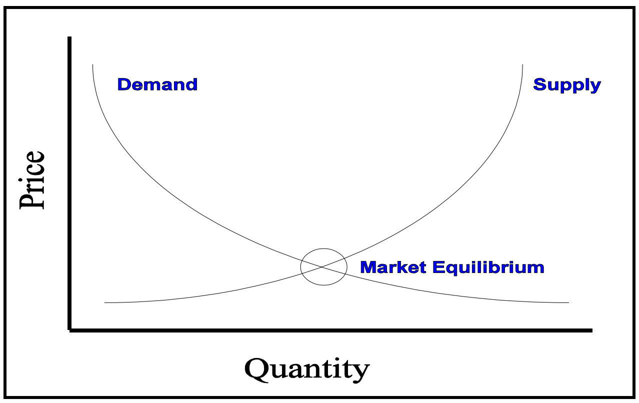

Figure 3: Competitive Commodity Market – Supply and Demand Curves

Electricity markets

Electricity markets (including Ontario) have two important characteristics, which mean that these equilibrium prices can reach very high levels for short periods of time, and can show considerable short-term variability. First, the quantity of installed generation is limited in the short term, so when demand rises quickly, it is not possible to immediately add new supply. As in all markets that exhibit this characteristic, electricity markets install some spare capacity (reserve). Secondly, since this reserve plant is infrequently used it is more sensible to build reserve plant that has low capital costs. But this generally means the reserve plant has high operating costs. In combination, these result in market prices rising to very high levels when demand periodically rises towards the level of installed supply.

Price inelasticity of demand

In consequence, the cost of incremental supply is relatively low until it sharply increases as the total supply capability for the market is reached at which point supply costs and price rise rapidly. This type of curve has sometimes been called a "hockey stick " supply curve. Electricity demand at any given moment is relatively price inelastic because factors, such as time of day, weather conditions and industrial production schedules, have a larger impact on demand than the real-time price. In addition, about half of the electricity load in Ontario is currently under a legislated, fixed-price arrangement, removing the incentive to adjust consumption in response to real-time electricity price changes.

Electricity market realities

As a result, the current electricity market in Ontario looks much more like that depicted in Figure 4. The slope of the demand curve is nearly vertical (as in D_1 and D_2), and the slope of the supply curve is steep where demand is close to available supply.

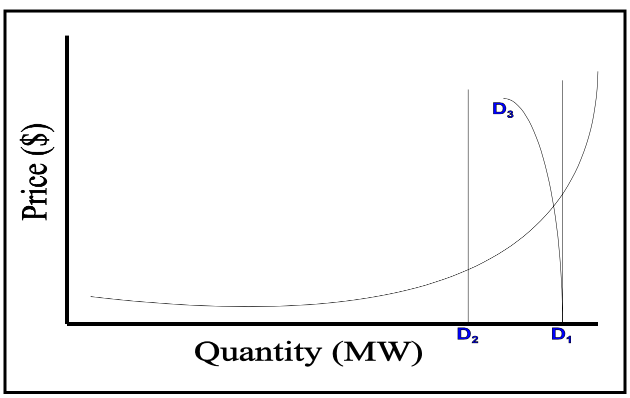

Figure 4: Ontario Electricity Market – Illustrative Demand and Supply Curves

Potential benefits of DSM and DR

Hence, one of the mechanisms that DSM and more particularly DR, can operate is by increasing the price elasticity of demand (or perhaps restoring it, to the extent that it is artificially reduced by other factors). If consumers reduce demand in response to increased price, then the volatility of market equilibrium prices will be reduced. In the long-term, assuming that the supply curve is relatively fixed, the market equilibrium price should decrease as DSM tends to shift the demand curve back (from D_1 to D_2 in Figure 4) due to sustained reductions in energy consumption.

DR changes the shape of the demand curve (from D_1 to D_3 in Figure 4) through consumers reducing consumption when prices are high. When the demand curve intersects the supply curve in the blade portion of the "hockey stick", small changes in demand will result in large changes in price. Navigant Consulting estimates that a demand reduction in Ontario of just 50 MW whenever market prices were over $150/MWh would have saved over $26 million since market opening; 70 MW would have saved approximately $50 million[2].

Effective DSM and DR reduce peak demand and reduce the need for new generation capacity. Since the transmission and distribution networks are generally dimensioned according to the level of peak demand, DSM and DR also reduce the need for upgrades to the distribution and transmission networks. They can help maintain the balance between electricity supply and demand and preserve the quality and security of supply. This could help to reduce electricity prices in the short-term and optimize generating and network capacity requirements in the long term. As a result, DSM and DR may improve energy efficiency and reduce impacts on the environment.

DSM and DR that increase demand elasticity also reduce the ability of generators to exert market power at likely times of shortage, reducing concerns that the market is prone to anticompetitive behavior.

Examples of DSM and DR actions taken in recent power emergency

The tremendous consumer response to the recent power emergency demonstrated many types of DSM and DR. These included:

- energy conservation through reducing air conditioning and not using appliances;
- energy efficiency through quickly installing compact flourescent lights and using microwaves rather than electric ovens;
- fuel switching through using dual fuel backup generators and barbequing;
- load shifting by moving production to overnight shifts and putting off laundry, cooking, or running dishwashers until after 8 pm; and,
- load curtailment, either voluntarily by reducing industrial production (i.e., DR), or involuntarily through rolling blackouts in the earliest period.

Involuntary curtailment is not a sustainable option for both economic and social reasons. The challenge for Ontario is to identify and organize sustainable activities in DSM and DR.

3 FRAMEWORK FOR DISCUSSION AND ISSUES TO BE ADDRESSED

3.1 Framework for Discussion

An overview of the Ontario gas and electricity sectors is provided in Appendix A.

Overview of Ontario gas and electricity sectors in Appendix

The basic question to be considered is: "What policy framework is needed to facilitate implementation of DSM and DR, including load aggregation, in Ontario's Electricity Sector?" Consultation will also consider how this framework can be appropriately applied to the role of the distributor in the natural gas sector.

What policy framework is needed to facilitate implementation of DSM and DR, including load aggregation?

The gas and electricity sectors can be described as chains of participants whose interaction is governed by a foundation of rules.

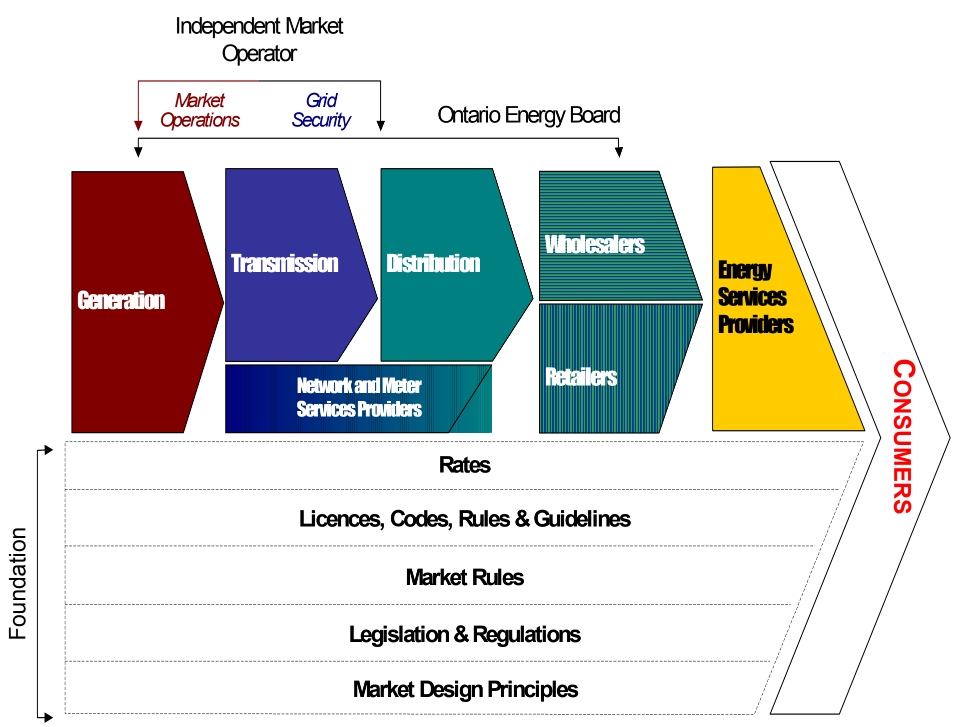

Figure 5: Overview of the Ontario Electricity Sector

Figure 5 is a simplified representation of the electricity sector; the actual number of stakeholders and market participants is considerably more numerous and complex.

Structure of the market

As illustrated in Figure 5, the electricity sector consists of a number of participants (i.e., generators, transmitters, ...etc). The structure of the sector and the conduct of the participants are bound by defining foundation (i.e., legislation, regulation,... etc). This foundation is the responsibility of government, the IMO, and the OEB to develop and change.

Framework for consultation

These primary elements; i.e., participants and foundation, will be used in consultation with stakeholders to describe and assess options for a policy framework to implement DSM and DR in Ontario. A more detailed description of each element is available in Appendix A.

3.2 Issues to be Addressed

Based on consideration of the participants to and the foundations of the electricity and gas sectors in Ontario, the following issues should be addressed in consultation.

Objectives for DSM and DR

- What are the objectives for DSM and DR?
  - To reduce demand on the system?
  - To reduce consumer bills?
  - To reduce resource consumption?
  - To encourage correct pricing?
  - To reduce emissions?

  - To promote the use of cleaner energy sources and energy efficient technologies (i.e., market transformation)?
  - Other?

Stages of DSM and DR implementation

- In general, the various stages of DSM and DR implementation are:
  - identifying objectives and opportunities;
  - funding;
  - design and delivery; and
  - monitoring and evaluation.

  These stages are illustrated in Chapter 4.

Opportunities and benefits

  How would objectives be set? How would opportunities to meet those objectives be identified and screened? How would costs and benefits to consumers and the entire system be measured?

  How can DR be offered and measured in the IMO administered markets?

Roles and responsibilities

  Who might be involved in each stage (i.e., generators, transmitters, distributors, wholesalers, retailers, service providers, load aggregators, consumers, OEB, IMO, government, third party agencies)? Who should be primarily responsible for each stage? What are secondary roles and responsibilities of other participants?

What has been the DSM and DR experience in the Ontario market? Are incentives necessary to stimulate activity? If so, where are they needed?

Incentives

- If the local distribution company has a role:
  - Is it the same in the gas sector as in the electricity sector?
  - How is it defined (i.e., objectives and opportunities, funding, design and delivery, monitoring and evaluation)?
  - What kind of oversight is required (e.g., cost-of-service or target-oriented)?

Distributor role

- Are the sector foundations (i.e., market design, legislation, and regulatory instruments) creating barriers to DSM and DR involvement? If so, how would they have to change to allow participants to fulfill their recommended roles?

Needed changes to market design, legislation and regulatory instruments

3.3 Important Considerations

Important considerations

There are a number of important considerations that should be kept in mind when studying the above issues, including: concurrent initiatives, symmetry between the electricity and gas sectors, and distribution unbundling.

3.3.1 Concurrent Initiatives

There are a number of initiatives currently underway in Ontario that may help to inform the Board, including:

- An Electricity Conservation and Supply Task Force was established to provide an action plan outlining ways to attract new generation and identifying mechanisms for DSM.

Electricity Conservation and Supply Task Force

- Establishment of an IMO Demand Response Advisory Group to develop a detailed blueprint for enhancing DR in Ontario. The work includes not only consideration of the IMO-administered markets but also the retail electricity market, and is intended to identify a full range of issues impeding load responsiveness in the markets today, and a practical set of initiatives to address them.

  The proposed blueprint prepared by Navigant Consulting Inc. (Navigant Consulting)[3] for the IMO provides a number of recommendations for how greater DR can be achieved in the short-term (in 2003), the medium term (by 2005) and the longer term.

IMO seeking ways to enhance DR in Ontario

- An Electricity Distributors Association (EDA) working group developed[4] specific proposals for electricity distributor-led DSM initiatives for submission to the government, and established a distribution industry position on principles associated with electricity distributor-related DSM.

Electricity Distributors Association examination of DSM

3.3.2 Symmetry

Symmetry between the electricity and gas sectors, while on the surface desirable, may not be appropriate in all matters and therefore needs to be carefully examined. For example, in the electricity sector, legislation restricts the business activities of electricity distributors. In addition, the Board licenses electricity distributors

Symmetry with electricity in all matters may not be appropriate

and a broad range of electricity market participants. Gas distributors are not licensed by the Board and the Board has a more limited power to make rules with respect to the activities of gas distributors. In the gas sector, the distributors have evolved over 40+ years of regulation under the Board. Further, gas distributors have carried out DSM activities in a manner approved by the Board for over 15 years. In the electricity sector, the Board has yet to establish an approach to DSM and DR.

3.3.3 Distribution Unbundling

Inconsistency between current policy direction and market evolution/design

In the gas and electricity sectors utility services are unbundled (i.e., commodity sales and distribution services). The incremental changes, including distribution unbundling, seen in Ontario's gas sector since 1985 have occurred as a result of iterative consultation processes involving the gas companies, stakeholders, the Board and Government. The changes implemented in Ontario's electricity sector since 1998 have unbundled and redefined electricity distributor responsibilities and obligations in the new market. Current policy direction introduces inconsistency between any mandated distributor involvement in DSM and the market design which made the distributors "wires only" businesses.

4 APPROACHES TO DSM

__The advent of retail competition in energy markets favors market-based approach; while heightened concern over climate change calls for public-policy based approach__

DSM started in the energy crisis of the 1970s and flourished in the era of vertically integrated utilities. A brief history of DSM and DR in Ontario is included in Appendix B. In recent years, the global trend to restructure energy markets has led to a reliance on market prices to determine energy demand. At the same time, new emphasis on environmental issues including climate change and natural resource exhaustion has worked toward centralized planning and activities. These contradictory forces have led to a great diversity in DSM frameworks even in a deregulated context. These approaches range from Sweden's federalized market transformation initiatives to the more traditional integrated resource planning required of distributors in Australia. Moreover, several jurisdictions have recently revised their approach to demand management, with the most common trends involving either the creation of sophisticated incentive schemes to reward distributors for achieving demand reductions, or the transfer of the distributor's DSM duties to a central authority or third-party provider. Experience in other jurisdictions, notably the UK, has shown that DSM measures frequently need inducements other than market prices to have significant impacts on demand levels in newly restructured markets.

The following sections summarize the result of research that surveyed 25 different jurisdictions. More detail on DSM in the jurisdictions is available in Appendix C. Most examples are in electricity, however they are helpful to identify common principles and policies.

DSM in restructured markets varies within a spectrum of possibilities as illustrated in Figure 6. As the overarching policy varies from fully market-based to fully public policy-based, the approach varies from voluntary to legislated and the responsibility for the stages of objective setting, funding and development likely shift among players.

Responsibilities with regard to DSM can vary within a spectrum, as illustrated in Figure 6

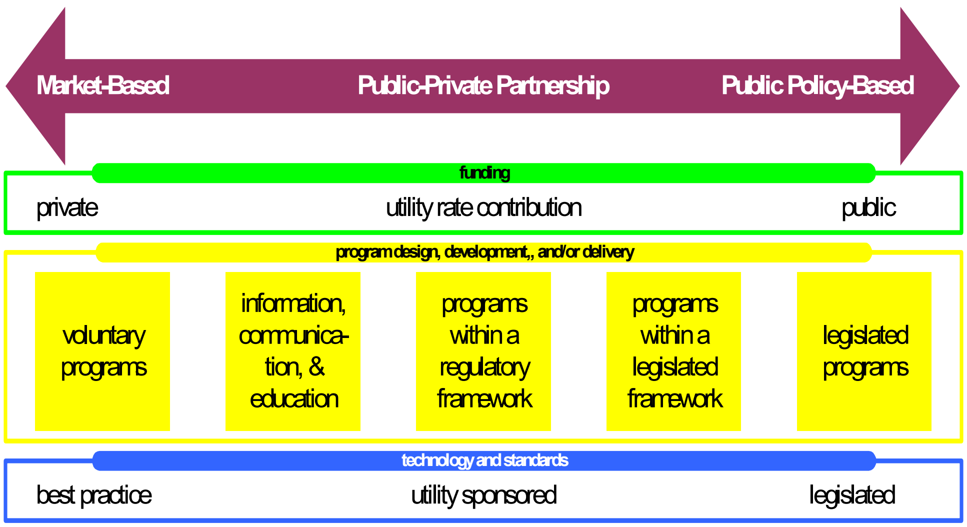

Figure 6: A spectrum of DSM responsibilities

The responsibilities may be divided in many different ways among federal and local governments, independent agencies, distributors, and other market players. In particular, the distributor's role can range from passive observer of governmental endeavours to chief architect and administrator of all demand management measures in its jurisdiction, with most situations lying in between these extremes. As markets have evolved over the past decade, many have adopted "hybrid" DSM frameworks in which traditional utility programs have been supplemented by governmental policy initiatives supported by distributor-collected funds.

Implementing DSM generally involves the following stages:

Stages of implementation of DSM

- Identifying objectives and opportunities;
- Funding;
- Design and delivery; and
- Monitoring and evaluation.

Key questions in all stages include: who might be involved; what are their roles and responsibilities; how do they relate to / with others involved?

Although this paper addresses all stages, it concentrates on the two areas that show the most diversity (i.e., funding and design/delivery) and gives examples of options for stages from other jurisdictions. The models and examples are not exhaustive. They are meant to spur discussion and highlight issues, not to limit approaches.

4.1 Identifying objectives and opportunities

How might objectives for DSM be set? How might activities to meet the objectives be identified and screened? How would any costs and benefits to consumers and to the entire system be measured?

DSM and DR objectives will vary depending on the body setting the objectives. The setting of objectives is often closely linked to funding issues. The body that pays for design and development is often also the one that sets the objectives. The following illustrates for discussion purposes various roles that government, system operator, distributor, OEB, and/or consumer may have.

4.1.1 Government or the regulator sets objectives

Government

This makes it easier to include broader societal benefits and allows co-ordination with other government priorities such as water conservation and management, emissions targets or support for disadvantaged groups.

4.1.2 IMO sets objectives

IMO

Recently, the Standard Market Design (SMD) developed by the U.S. Federal Energy Regulatory Commission (FERC) proposed that Load Serving Entities (LSEs) doing long-term resource adequacy planning should weigh the opportunities for new generation, improved transmission and load management on an equal basis.

The IMO performs system evaluation plans to identify necessary system upgrades as well as market surveillance to find the exercise of market power. Similar to the SMD, the IMO could consider demand-side resources on an equal footing with supply resources and transmission upgrades to meet future needs.

This would allow the IMO to optimize system operation, overall or in specific ways, e.g. to reduce peak demand or to relieve congestion. The IMO has direct relationships with large consumers who may provide the largest opportunities for significant reaction.

4.1.3 Distributors set objectives

Distributors

The Distributors could set objectives in line with IRP goals and identify opportunities through their closer relationship with consumers.

Energy industry asset management decisions require the balancing of supply-side[5] utility investment and demand-side[6] customer usage. DSM encompasses those actions taken by a utility or another agency which are expected to influence the amount or timing of a customer's energy consumption. IRP was traditionally applied to planning at vertically integrated utilities but the idea may be equally useful for Distributors.

This is similar to the approach to DSM by distributors in Ontario's natural gas sector for many years. See Appendix B for a history of DSM in natural gas in Ontario.

4.1.4 Regulator sets targets and Distributor identifies opportunities

Regulator

Regulatory regimes in which energy efficiency is made a core responsibility of the Distributor have grown more complex in recent years, with the development of incentive schemes that reward DSM achievement relative to target levels set by the regulator. Since these incentives often increase proportionately with DSM-produced reductions in energy consumption, regulators typically grant Distributors considerable freedom to devise innovative schemes and allocate funds across programs in such a way as to maximize the DSM dividend. Some argue that the incentive schemes make load reduction so profitable for distributors that they become less concerned with cost-efficient delivery, social aims, or system benefits. Thus any resources saved by the regulator through devolving program design to the distributor are often diverted to cost-benefit analyses and periodic assessments. Both the establishment of targets and the measurement of performance can grow contentious. This approach to DSM remains popular with distributors because of the financial incentives, while regulators appreciate that the entity in closest touch with end-users can tailor demand management programs to their preferences. British Columbia, California, and the UK all provide examples of how a target-based approach can be implemented within a performance-based framework. Utilities in those jurisdictions have offered a wide variety of demand-side options to customers which encourage conservation of both electricity and gas.

A handful of jurisdictions have integrated provision for DSM with their PBR plans to help formalize the distributor's monetary incentive for the pursuit of greater energy efficiency through its customers. Just as a company's service quality performance can be rewarded or penalized through adjustments to the PBR plan, so too can a company's achievements in reducing consumption relative to a pre-determined target level (i.e., their "demand-side management performance").

Even in the absence of performance-based ratemaking, numerous jurisdictions have created financial incentives for distributors to optimize their DSM efforts. In both New Jersey and Minnesota, distributors are responsible for formulating and implementing DSM, albeit with a sizeable role for the regulator to ensure that costs are minimized and under served communities are reached.

4.1.5 Consumers identify opportunities

Consumers

The primary objective for the consumer in taking action is bill reduction. Declining block delivery rates and flat commodity pricing make action less likely; however, consumers may also have social or environmental objectives.

4.2 Funding

How might DSM be funded; and who may be responsible (i.e., who pays)?

Research from other jurisdictions, shows several common funding possibilities.

4.2.1 The user pays for energy efficiency because high prices make action attractive

User pay

This is the market-based approach. When prices are high (consistently, cyclically or on a volatile basis) consumers find it worthwhile to invest in technologies that save energy or shift its use to lower-price periods.

In Ontario, many large electricity consumers signed fixed price contracts with OPG, wholesalers or retailers that reduce price risks and the financial rewards of load reductions. Some contracts actually require minimum consumption levels to guarantee low prices. In addition, nearly 50 per cent of Ontario's total load is guaranteed a fixed price of $43 per MWh by legislation until May 1, 2006.

Experience in other jurisdictions, notably the UK, has shown that additional economic inducements are usually needed in restructured markets. Consumers may be waiting to see how the market settles before making decisions to invest in technologies that will conserve energy or allow load shifting (efficient equipment, timers, meters, etc.) or they may not have adjusted to thinking of energy as a commodity. In any case, consumer concern regarding volatile energy prices tends to increase the likelihood that government will intervene to control and/or reduce prices. Thus consumers have either been unwilling or unable to change their energy use.

4.2.2 The user pays for energy efficiency because of government initiatives that increase the baseline of equipment efficiency

Standards and labeling

This is the kind of initiative where the consumer buys more efficient equipment (that may be higher priced) because of standards or labelling programs. This may be combined with a targeted information or leadership program that demonstrates cost effective implementation. Examples of the leadership approach are the R-2000 home building program and the Better Buildings Partnership.

Ontario's *Energy Efficiency Act* sets minimum energy efficiency standards for designated appliances and energy-using equipment. These standards are developed in consultation with equipment manufacturers to ensure that industry competitiveness is not harmed and Ontario does not become a "dumping ground" for less efficient equipment disallowed in other jurisdictions. These consultations also ensure that the minimum standards are attainable at reasonable and economic costs to consumers and manufacturers.

Labelling and leadership can spur enough purchases to increase market penetration and shrink price differences so that increases in the minimum standard are uncontested.

Another example of government-led, user-pay initiatives is the Natural Resources Canada Office of Energy Efficiency (NRCan) pursuit of longer-term objectives to gradually upgrade the energy performance of Canada's residential and commercial buildings. Developers, designers and builders are encouraged to voluntarily adopt stringent energy efficiency standards formulated by NRCan. In turn, these standards stimulate architects and builders to use energy efficient designs (including envelope and HVAC improvements) and other manufacturers to develop new products such as heat recovery ventilators and high-performance windows. Also, NRCan recently adopted the ENERGY STAR labelling program from the US to promote the gradual replacement of aging appliances with more efficient counterparts. In a sense, the DSM initiatives undertaken by the federal government are geared toward long-run market transformation, compared to more traditional approaches that improve energy efficiency one customer at a time.

4.2.3 The government funds directly out of general revenues

Government funds

In some jurisdictions, the government administers DSM programs directly. This is typical when it believes that the economies of scale resulting from uniform delivery of DSM throughout its territory produce greater benefits than the diffuse efforts of individual distributors, which require investments in administration and oversight by each utility. Not having a role for the distributor lightens the regulatory burden of related hearings and performance reviews.

A hybrid approach is also common. The government funds certain broad-reaching DSM initiatives out of general tax revenues and distributors undertake more customer-oriented projects as part of account management. This approach is used in the UK and Canada, among others.

The pure “no involvement” role is observable in Sweden and Finland. A large percentage of DSM activity is designed and implemented by the federal government without any involvement by distribution companies. They have delegated oversight of DSM to centralized authorities, although other governmental agencies and industry organizations provide assistance in operating and monitoring certain programs.

In its final recommendations, the Market Design Committee in Ontario included the following:

5-5 "... the Ontario government should augment the Ministry of Energy, Science and Technology's efforts to encourage consumer energy efficiency. The Ministry should also exercise its authority to pursue energy efficiency programs beyond information and education programs, emphasizing cost-effective demand-side investments for consumers who are not targeted by private DSM providers. As these programs have social benefits for all citizens, it is appropriate to fund these programs using public monies."

The social benefits considered can go beyond the cost benefits that arise from the pricing "hockey stick", including health and conservation benefits, and greenhouse and acid gas reductions that are targeted by other policies. By co-ordinating efforts, larger benefits may be achievable in all areas.

Other jurisdictions have followed this type of funding regime for a number of years. Sweden and Finland in particular have ambitious funding programs that help industrial, commercial and residential consumers achieve efficiency.

Funding for the New York State Energy Research and Development Authority (NYSERDA) comes from a combination of general tax revenues, a public systems benefit charge transferred from distributors and voluntary annual contributions by the New York

Power Authority, the Long Island Power Authority, and a limited number of corporations.

4.2.4 Ontario Electricity Financial Corporation funds through avoided costs

OEFC funds

Currently, OEFC assumes the financial obligations of funding the statutory price when the supply-demand balance is tight and prices are high. It might be more cost effective to fund short-term DSM initiatives than subsidize consumption by low volume and designated loads.

This is a uniquely Ontario option, although California's situation is similar. The state government signed long-term fixed price contracts to avoid price volatility during the 2001 electricity crisis. These contract prices are now higher than spot prices. The state has had considerable success with demand reduction and is also running several new pilot projects.

4.2.5 Consumers fund through a Systems Benefit Charge

Systems benefit charge

Many governments established a surcharge to promote general societal good or overall system efficiency. Referred to as a "social benefits charge" (SBC) or as a "public system benefits charge" (PSBC), the surcharge is a per-kWh (i.e., volumetric), non-bypassable payment made by an energy consumer to support DSM endeavours. The payment may be collected by a distributor and given to either a government authority or a third-party. This funds-collection approach to DSM is popular in the U.S. New York, Vermont and Wisconsin have SBCs to fund centralized DSM administration by a designated agency.

Appendix C contains case studies that illustrate DSM frameworks in which distributors collect a PSBC and pass it on to a central agency to fund energy efficiency programs.

4.2.6 Distributors fund DSM programs out of revenues

Distributors fund

Distributors are closest to end-use consumers and may have an advantage in identifying DSM opportunities. However, the number and variety of distributors in Ontario may mean that DSM implementation varies across the province, opportunities are not the same for all consumers or that the cost of DSM implementation is an unfair burden on smaller distributors.

DSM activity tends to penalize distributors who charge on a volumetric basis. DSM reduces the volume of energy sold which therefore reduces revenue. And since distribution costs are largely fixed in nature, this reduces profits. As a result, either a complex scheme of incentives is necessary to ensure that targets are met. Or alternatively, the system of price regulation has to be adjusted to offset this disincentive. Unfortunately, either change can, if not done sufficiently well, result in incentives that are attractive that distributors pursue DSM without regard to either IRP or aggregate social efficiency. This can then lead to contention and, in turn, the expenditure of considerable resources in after-the-fact verification, cost-benefit studies and audits.

In certain instances, the distributor may act solely as a facilitator or educator by providing information to consumers on ways to voluntarily reduce and/or shift their energy use. This approach does not include monetary incentives and/or rebates.

Methods to foster demand-side action amongst consumers may include promotional campaigns stressing conservation, display of customer usage patterns on bills, educational seminars for businesses, and/or demand-responsive rates (e.g., interruptible, time-of-use, and real time pricing). The Internet has become a particularly effective tool in the facilitation process, as many companies have used their web sites to post energy-saving advice, on-line energy audit questionnaires, and links to contractors that can install energy-saving equipment. Some technically sophisticated companies have created Internet-based software packages that provide customers access to real-time load and price information, plus graphical summaries of usage patterns. Sponsorship and promotion of appliance labelling programs such as ENERGY STAR may also facilitate voluntary conservation.

A more active role for a distributor in facilitating DSM may be to determine the barriers to DSM within its service area and to make appropriate adjustments such as is the case with Norway (see Appendix C). An additional means of facilitation may involve providing customers with opportunities to both voluntarily and financially express their DSM preferences through various interactive programs, such as those provided by Nova Scotia Power (see Appendix C).

4.3 Design and Delivery

How might activities be planned, administered, delivered, and measured?

Design and delivery are actually discrete functions. It is possible to have one agency design a plan and use market channels to deliver it. However, in most jurisdictions the same entity that designs the plan is responsible for determining the method of delivery and for the success of the plan whether or not it delivers it directly. The following sections describe some common approaches.

4.3.1 Utilities deliver savings primarily through focussing on internal opportunities

Internal efforts by utilities

In a Transmission PBR proposal (September 1999), Ontario Hydro Services Company (OHSC, now Hydro One Inc.) addressed demand-side management. OHSC stated that regardless of how end-use related DSM is ultimately treated by the Board, it would continue to pursue internal energy efficiencies in its transmission system, primarily through ongoing reduction of line losses.

4.3.2 A government or regulatory agency develops and delivers programs

Government

As with funding, some governments believe that the economies of scale from uniform delivery of DSM produce greater benefits at lower cost. Another advantage of this approach is the opportunity to co-ordinate DSM with other government objectives such as renewable portfolio standards and greenhouse and acid gas emission reductions.

The energy efficiency plan overseen by the Canadian federal government is an example of a centrally mandated plan oriented toward technological solutions and market transformation. Technology development is financially supported by the CANMET Energy Technology Centre.

In Finland, the federal government established the Information Centre for Energy Efficiency (MOTIVA) in 1993 to distribute information, stimulate technological development, and promote the adoption of energy-efficient practices and equipment. A combination of a sense of public obligation and governmental pressure has resulted in significant energy efficiency gains by the business community. Finland's new action plan expands the DSM package and introduces a new orientation to reduce CO_2 emissions in response to the Kyoto Protocol.

Canada has also implemented DSM-related measures in response to Kyoto commitments, including incentives for energy efficient retrofits.

4.3.3 A third party agency or contractor develops and delivers initiatives

Third party

Governments who assume DSM responsibilities to capture economies of scale sometimes use a non-government agency or contractor to delivery programs. Advocates of third party delivery of DSM note that common incentive schemes that rely solely on parties with vested interests, i.e., distributors, to design and deliver programs may not serve the broader interests of the market as a whole.

In Norway, the potential misuse of SBCs for utility self-interest (e.g., marketing incentives or customer retention) was an issue. To address these concerns, NVE (the regulatory agency) established Regional Energy Efficiency Centres (REECs) funded by an SBC and owned in part by the utilities and third parties in each region. The REECs provide impartial energy efficiency advice, general information, historical electricity consumption data, and environmental emission assessments to a full range of customer groups throughout Norway. In addition to REEC offerings, utilities use business-based DSM measures such as real-time pricing and interruptible load agreements with large users to help customers avoid peak prices. These programs have provided substantial benefits to Norway's energy intensive industries, notably paper mills and aluminum smelters.

In 1975, New York developed a separate entity called the New York State Energy Research and Development Authority (NYSERDA) to administer SBC funds collected from ratepayers. See Appendix C for more details.

Efficiency Vermont, created in June, 1999, was the first Energy Efficiency Utility (EEU) in the U.S. A consortium selected by the Vermont Public Service Board, consisting of a fiscal agent, a contract administrator, and an advisory committee, oversees Efficiency Vermont. It is funded by a system benefits charge included in the bills of utility customers. See Appendix C for more detail.

In the United Kingdom, as part of their social obligations and licence conditions, all electricity suppliers serving domestic customers are required by the Office of Gas and Electricity Markets (Ofgem) to provide, free of charge, energy efficiency advice upon request and bill management assistance for low-income qualifying customers. See Appendix C for more detail.

Nova Scotia Power Inc. (NSPI), the principal supplier of electricity in the province, follows the UK and Norway examples for distributor-based DSM activity. NSPI does not directly deliver energy efficiency programs. It provides information, consulting, and auditing services targeted at reducing electricity consumption for homes and business. The NSPI website outlines customer services and provides information on free home heating and energy conservation analysis. The site provides information on topics ranging from how to read a meter to energy efficient products, supplies an energy calculator that determines the cost of operating household appliances on a bimonthly basis, and software for bill management and energy use analysis, including access to a customer's consumption history over the past 13 months.

New Jersey distributors collect a SBC allocated to energy efficiency and renewable energy programs. The funds are allocated to specific DSM activities through a comprehensive resource analysis proceeding. Shareholder incentives for good performance are provided through two means: 1) a shared savings mechanism through which distributors receive a negotiated share of net benefits, and 2) a standard price offer where the distributor pays a set price (corresponding closely with avoided cost) to customers and ESCOs for verifiable demand savings.

4.3.4 The Distributor designs and delivers programs in order to implement IRP

IRP

In vertically-integrated (i.e., fully bundled) utilities, DSM can be part of the utility's integrated resource plan (IRP) as a substitute for plant construction or grid upgrades. With industry re-structuring, and the break-up of the power supply chain, the rationale for distributor involvement in DSM may diminish. However, it is still compelling when DSM may avoid or deter costly upgrades or re-enforcement to the local distribution system. Distributors mandated to file periodic IRPs are able to develop DSM initiatives in the context of a holistic system overview, and pursue those initiatives where the program costs are less than the avoided costs of distribution system investment in the absence of DSM. This distribution resource planning approach evaluates the effectiveness of DSM projects relative to their avoided cost, rather than on the achievement of energy reduction targets regardless of cost. While this approach may require greater resources from both the distributor (to perform a comprehensive system analysis) and its regulator (to scrutinize the IRP and pass judgment on its conclusions), it may yield a better-targeted DSM package. Avoided cost are the total supply-side costs that are not incurred, or deferred into the future, as a result of the implementation of a DSM program. Avoided costs are usually taken to be the full marginal or incremental costs of supply that will be avoided[7], but definitions are not common in all jurisdictions.

In designing plans to meet future energy supply and demand needs, utilities may take into account energy efficiency and load-management programs, environmental and social factors, as well as direct economic costs and benefits, public participation, and the uncertainties and risks posed by different resource choices. The aim is technology neutrality so that "demand-side" resources (mechanisms and technologies that reduce or manage end-user demand) are treated with the same weight as "supply-side" resources (generation, transmission, or storage). Thus, "deferred" or "avoided" demand is treated the same as a future addition to electricity supply.

The IRP method is still most frequently observed in non-deregulated jurisdictions such as the states of Oregon and Washington; however, it provides the foundation for DSM in Australia's deregulated states. Some jurisdictions where restructuring is underway no longer require utilities to undertake IRP, or the measures associated with the IRP process.

4.4 Monitoring and Evaluation

How might activities be monitored and evaluated?

Monitoring

Monitoring is the ongoing review of performance and results that is used by the design and development arm to make adjustments to programs in the field between evaluations.

Evaluation

Evaluation is often closely linked to who sets the objectives. If government or the regulator sets the objectives, they usually approve the programs. Where the Distributor designs and delivers programs, the regulator usually oversees activities. Evaluation comprises two parts; approval of the proposed plan and monitoring of the effect. When a third party or agency delivers the programs, an independent audit is usually made.

Approval

Approval includes some method of measuring and comparing expected results so that the most cost effective plans are promoted. This involves making assumptions based on load research and analysing for the sensitivity of those assumptions and applying some threshold test. This may be the Total Resource Cost Test, the Utility Test, the Societal Cost Test or some other measure.

Audit

Auditing is an attempt to verify the results of the plan. It can be difficult to measure the effects of DSM activity in load or consumption because other factors have changed at the same time. Audit programs may seek to verify participation and the assumptions in the original plan and therefore cause modifications within a more formal planning cycle.

5 APPROACHES TO DR

DR focus at electricity wholesale market

The four stages of implementation (objectives, funding, design and delivery and evaluation) are also applicable to the implementation of demand response. DR is a less significant issue in natural gas than in electricity, and will likely be a focus in the IMO administered markets. Therefore, objectives may best be identified by the IMO and even design and delivery and evaluation are also through the IMO.

The method and level of funding is under consideration and is liable to differ based on the category. Demand response can be categorized in three broad areas: price response, demand bidding and voluntary load shedding.

5.1 Price Response

Price response DR is like "user pay" DSM

Price response is analogous to "user pay" in the previous chapter. Price response occurs when consumers respond to high prices by reducing or shifting load. Their only action is to reduce consumption and their only reward is to avoid paying for high-priced electricity. The most effective price response occurs when consumers know and are charged the value of electricity used at specific times and they are able to adjust their use in a dynamic manner. The consumer does not otherwise have to be an active participant in the wholesale market. However, the dynamics of inelastic demand and supply curves (the supply "hockey stick") means that a small reduction in total demand can result in a large reduction to the market clearing price. Those who continue to consume through this period will benefit from the actions of others.

Load shifting rather than load reduction

A significant amount of price response for most consumers is actually load shifting, i.e., there is no reduction in demand it is just "time shifted", so cumulative environmental benefits may be less than for pure conservation. However, because most peaking plants in Ontario are fossil-fuelled, there are still substantial environmental benefits from reduced greenhouse gas and acid gas emissions.

Information and measurement are important

Hindering a more effective price response by retail customers is the general lack of accurate forecasts and timely information for consumers about market prices and the ability to measure actual patterns of individual consumer consumption for billing purposes. Without interval meters, conserved load is not credited to a specific time period but assigned according to a net system load shape. Loads shifted within a meter-reading cycle will receive only the benefit of a reduction in peak price but will not be attributed to the consumer taking action.

Under current legislation, approximately half the load in Ontario has a fixed energy price and effectively no market-based price signal. The number of these consumers that have interval meters and may be capable of price responsive behaviour is unknown, but estimated to be small.

Locational marginal pricing

DR can operate effectively under a variety of electricity market mechanisms, including locational marginal pricing (LMP). Adding congestion costs to the real-time price of the commodity may further encourage price responsiveness.

5.2 Demand Bidding

Demand bidding may involve financial incentives and penalties like some DSM

Demand bidding enables consumers to actively participate in electricity trading by offering to undertake changes to their normal pattern of consumption in return for financial compensation. For demand bidding, consumers offer non-consumption into a market on an equal footing with supply and are called in merit order (see Appendix C) to fulfill their bid. This makes these consumers active market participants. In the IMO real-time energy market, loads that are able to bid and respond on 5-minute intervals are “dispatchable loads”. Failing to fulfill their bid when called results in penalties. Demand bidding programs are geared toward temporary decreases in load under peak system conditions, and are generally used by larger loads that are active in the wholesale market to reschedule loads or make specific, previously agreed load reductions.

Some demand bidding programs allow market participants, utilities, load aggregators, other load serving entities, and large users to bid in their willingness to curtail a sufficiently large (usually not less than 100kW) amount of their energy use directly into an ISO-administered wholesale market. Demand bidding may be on a 5-minute, hour ahead or day ahead basis. However, there are also utility-specific demand bidding programs in which consumers register with their own distribution utilities to curtail load (though these generally target bundled-rate customers).

Consumers can bid individually or as an aggregated group

Consumers can participate in demand bidding individually or as a group, with bidding undertaken either directly with the market or through a load serving entity (utility, electricity retailer, broker or trader) acting as an 'aggregator' of numerous bids. In theory, any consumer can participate in demand bidding so long as they have the flexibility to make changes to their normal electricity demand profile and install the necessary control and monitoring technology to execute bids and demonstrate bid delivery. In practice, minimum bid rules and the ability to respond to dispatch signals limits the direct participation to large consumers with either backup generation or the ability to switch fuels or curtail production.

Smaller consumers willing to participate in demand bidding programs could do so through load aggregators. Load aggregators contract with customers willing to curtail their consumption if energy prices exceed a certain level, then submit these bids into the merit order for each hour's supply-demand schedule. Of course, participating consumers will require load controlling equipment to fulfill their obligations to curtail demand if the aggregator's bid is accepted.

Retail level activity includes load control

Biddable demand from the retail market is limited. The necessary load control and metering technologies to make retail consumers "dispatchable" are not in general use in Ontario except for some limited water heater load management facilities. Navigant Consulting estimates that the infrastructure exists for water heater load response of 45 to 67 MW[8]. However, to capture retail market load response as biddable demand in the IMO administered markets would likely require considerable investment in load control, communications and metering technology and equipment. While it may not be efficient to invest so that all retail load can participate, it may well be efficient to target such investment at a small number of high demand retail customers.

Some Distributors have used load control as a form of DR. In Ontario, distributors focussed on residential water heating as a controllable load to reduce peak demand and decrease system charges. The load is usually metered, but some distributors may have had rates where the load was associated with a flat rate, un-metered supply.[9]

In 1999, 12 electricity distributors had a controlled load rate, and 24 distributors had a flat water-heating rate as part of their bundled rate schedules. By the end of 2001, with rate unbundling, no distributors offered controlled load rates for water heaters and only four distributors maintained flat water-heating rates.

For the Ontario market, the Market Design Committee specifically recommended demand-side bidding for the new Ontario market:

5-4 ... the wholesale market design should provide for demand-side bidding (to allow large customers and demand aggregators to modify their demand during peak periods).

This recommendation, when translated into market rules, directed the IMO to consider and assess the ability of demand-side responses for relieving expected supply shortages in the market (generation or network capacity).

In the IMO market rules, dispatchable loads, i.e., loads that can respond to market prices by reducing demand in periods of high prices, or, increasing demand when prices are low, are treated the same as generator-based supply. In fact, at various times the IMO has stated that dispatchable loads should be considered as another supply source. This means that they must be able to respond to automatic dispatch instructions on 5-minute intervals.

Economic trade-offs

However, in reality, loads do not behave or respond to electricity price signals in the same manner as generator-based supply. Loads use electricity as a productive input for some other manufacturing or service activity that is the primary focus of the firm. Generators are focussed only on providing electricity. Therefore, it is unrealistic to expect that the same types of market rules that work well for pure suppliers would translate well to loads, other than exceptional cases like aluminium smelters.

Experience in the Ontario market to date supports this conclusion. Based on the number of customers that were on Ontario Hydro interruptible rates, there is about 600 MW of dispatchable load in the province. However, to date, wholesale market participants have provided only a fraction of that amount of dispatchable load in high-price periods.

Some reasons cited for this lower participation are:

- Many industrial consumers (that were potential dispatchable loads) signed rate supply contracts that were grand fathered by regulation to apply after market opening. Fixed, preferential pricing insulates loads from the need to respond to market prices.
- Operational concerns and other requirements such as the need to operate production facilities at high capacity levels to fulfill contract obligations.
- Few dispatchable loads are able to respond to dispatch instructions at five-minute intervals. Most production processes require longer to shut down and alternate generation cannot be brought online that quickly.
- The pre-dispatch prices and schedules often mismatch with real time prices and schedules. This mismatch causes some

> loads to be dispatched off, based on pre-dispatch prices, while the resulting real time price drops below their dispatch off level. Uncertainty about the benefits of active participation in the market is a barrier to securing more dispatchable load.

IMO consultation

On December 20, 2001, the IMO initiated consultation on "Priorities for Future Market Development". As part of this consultation, the IMO was seeking market participant views on encouraging dispatchability and demand-side bidding to support demand responsiveness in the wholesale market.

> "[One way to support demand responsiveness is to] make it easier or more attractive for large commercial and industrial customers to become dispatchable by the IMO, and thereby automatically responsive on a five-minute basis. Loads must register as dispatchable if they wish to offer operating reserve, and be paid for it, but some loads feel that the opportunity to be paid for operating reserve is insufficient incentive to join the market as dispatchable facilities. They seek to be paid directly for having their energy consumption interrupted during overall supply shortages. Several ISOs in the U.S. have implemented special 'interruptibility' payments to loads, partly to deal with concerns about market power, and partly to deal with price spikes. The IMO has begun explorations of this issue with dispatchable loads in Ontario, and has identified it as a potential top priority matter to investigate over the short term.

> The other aspect of the question is to find ways to encourage price responsiveness among those wholesale market participants who elect not to become dispatchable. Some loads may not be able to respond to five-minute or even hourly signals, but may nevertheless be able to shift their production schedules to shave peak loads, etc. The market evolution should be such that it fosters such initiatives by market participants. Minimally, the market rules could be reviewed to ensure that they do not inhibit such beneficial developments."[10]

The IMO's hour ahead dispatchable load program

The IMO's Market Evolution Program addresses some of the limitations of the existing dispatchable load program through rule changes and some new facilities. The primary new facility is the Hour Ahead Dispatchable Load (HADL) Program.

The HADL permits loads that were previously non-dispatchable to plan their consumption and be compensated for reduced loads even if the real time price drops below their HADL offer price. HADL dispatch instructions are based on the three-hour ahead pre-dispatch prices, giving HADL participants two hours to reduce consumption and maintain the reduction for a full hour. In addition, HADL participants are able to split their load behind the meter into dispatchable and non-dispatchable portions.

There are some limits on the program:

- It is available on business days from 7a.m. to 11p.m.;
- Loads must offer at least 1 MW of reduction;

- A revenue wholesale meter registered with the IMO is required for the participating load although the IMO will consider other arrangements to measure load response;
- HADL is only available to previously non-dispatchable loads, i.e., loads participating in current dispatchable load programs are ineligible ; and,
- Dispatch instructions will be issued no earlier than three hours and no later than two hours before the dispatch hour. Loads have five minutes to respond to instructions and indicate whether they will comply. There are no penalties for not accepting a dispatch order within the five-minute response period.

The HADL is quite new and it is unknown how much load it will affect.

In other jurisdictions dispatchable load makes small, but important contributions to improving market efficiency. Alberta had a bidding program that enlisted 250 MW of load that was "dispatched out" when prices rose above about $100 Cdn./MWh. This program is still available but has not been actively used by loads for several years.

California's experience

In California, there is a statewide Demand Bidding Program (DBP) created by Executive Order D-39-01 and funded by the California Department of Water Resources (CDWR). All existing participants in the Discretionary Load Control Program (DLCP), administered by the California ISO, and the utilities' Voluntary Demand Reduction Programs (VDRP) were rolled into this program. Total load participation in this program has been about 1,000 MW through the summer of 2001.

The DBP is a voluntary electric-load reduction program. Participating businesses commit to reducing their load on a day-ahead basis, and receive financial incentives. The program allows the CDWR to reward local businesses for reducing demand rather than paying out-of-state suppliers a higher price for additional electricity. All three major utilities in the state (Southern California Edison, San Diego Gas and Electric, and Pacific Gas and Electric) participate in this program.

For end users to participate in the DBP, they must have the ability to reduce electric load by at least 10 per cent, with a minimum reduction of 100 kW, and should not be already exposed to real time pricing. Participants must sign a contract and agree to participate in the program for 12 months. They receive a credit applied to their monthly electricity bill for verified electric load reductions that they implement following the acceptance of their bid. In addition, to help them monitor their usage, some utilities provide participants with upgraded metering equipment and a communication link between the meter and an internet service at no cost. Every day customers may log onto their utility's web site to place a curtailment bid for the next day by 1:00 p.m., and to check after 5:00 p.m. to see if their bid was accepted or rejected by the CDWR. Customers will be given the opportunity to submit bid commitments in four-hour blocks: 8:00 a.m. to 12:00 p.m., 12:00 p.m. to 4:00 p.m., and 4:00 p.m. to 8:00 p.m. The customer must bid the same price and load commitment (in kW) for each of the four hours within a block of time.

Australia's experience

In Australia, there has been virtually no demand-side bidding in the National Electricity Market (NEM). In March 2000, NECA (the National Electricity Code Administrator, the independent system operator) undertook a survey on demand-side participation in the NEM.

NECA found that a key disincentive to using direct demand-side bidding, as perceived by end-users, was the requirement for absolute symmetry between the rules governing the supply and demand-sides of the market. The market rules were designed primarily for the supply side of the market, particularly generators, and impose high transactions costs on demand-side bidders. NECA sought flexibility in the market rules to encourage demand response.

In September 2000, NECA proposed Code changes to make demand-side bidding more attractive to end-use customers. These changes sought to address the perceived barriers to demand-side bidding by:

- restructuring and simplifying the arrangements in order to improve the attractiveness of registering as a scheduled load;
- increasing flexibility for loads seeking to switch between scheduled and market (non-scheduled) loads;
- addressing the sanctions on market customers for non-conformance by scheduled loads; and,
- managing non-conformance by scheduled loads, with NECA applying constraints or a default dispatch bid on the participant's behalf.

New York's experience

New York has a successful demand bidding program. In early 2001, the NYISO began its day-ahead demand response (DADR) program that allows LSEs to submit bids that indicate their willingness to reduce demand at a specific price level. These bids are "dispatched out" on a merit-order basis. Under this program, load reduction bids are allowed to set the locational marginal price (LMP). A customer whose load reduction bid is accepted would normally be paid the greater of its bid amount or the LMP. However, until October 2003, those bidders that do not own or control a local generator, will receive an additional incentive credit related to the degree by which their demand reductions lowered the market-clearing price.

5.3 Voluntary load shedding

Voluntary load shedding

Economic demand response

Voluntary load shedding programs (curtailment or economic demand response) involve specific payments to consumers who are willing to cut demand when the market reaches certain levels, measured either in price or capacity. Voluntary load shedding differs from Demand bidding in that there is a one time sign up as opposed to periodic bids and control rests with the ISO. The payment may be for a specific incident or a general payment for availability (e.g., interruptible rates or capacity payment). Load aggregators may also consolidate enough consumers to participate in voluntary load shedding. Voluntary load shedding is often used when the system is at maximum capacity as one step short of rolling blackouts.

IMO's emergency demand reduction program

The IMO addressed voluntary load shedding through a temporary Emergency Demand Reduction Program (EDRP). The EDRP was a pre-arranged, voluntary load reduction program that could be activated on the IMO's initiative during an Emergency Operating State. The EDRP was for reliability purposes only and was not intended to respond to price changes. The IMO enrolled 342 MW of load in the EDRP from seven Wholesale Market Participants at eleven facilities. The initial program was for one year, ending in April 2003. The IMO extended the program for another 12 months, beginning May 1, 2003.

New York's program

New York also has a supplemental emergency demand response program (EDRP). This program allows participants to pledge load reductions to be triggered under dire system conditions, in exchange for payments equalling the higher of $500/MWh or the real-time zonal market price. To date, 13 load-serving entities (LSEs), 9 load aggregators and 7 end-users have either registered or are in the process of registering for the EDRP. The total capacity that could be curtailed under this program is about 700 MW. The New York ISO intends to devise a third demand-reduction plan that would permit loads to specify a price above which they no longer wish to buy energy from the day-ahead market.

6 LOAD AGGREGATION

Load aggregation

Load aggregation is a method to allow gather the activities of smaller consumers to meet the thresholds necessary to participate in markets. This could be for demand bidding or contracting conservation as a long term resource.

Interpretation

The term "aggregator" can be interpreted narrowly or broadly. Interpreted narrowly, it refers to small retailers that aggregate demand from relatively small, specific customer groups. For example, an aggregator may serve all restaurants or retail outlets within a region.[11] In England and Wales and Australia these types of transactions are often referred to as "roll-up" deals.

Common factors in deregulated markets

To date there is little evidence that these types of load aggregators participate in demand-side bidding. This reflects a number of common factors in deregulated markets:

- demand-side bidding schemes are not widely available in restructured markets, with the exception of one or two cases (California and New Zealand, for example), where severe system stress has led to extraordinary measures; this type of aggregator is generally small and poorly capitalized; they are not able (or allowed by financial institutions) to take significant risks such as short-term trading in spot markets;
- significant barriers to demand-side participation[12] remain for most customers, even when aggregated; and
- smaller customers that are capable of a demand response are often best served by an energy service company. ESCOS are able to provide less risky savings, over a longer time period,

and almost never use demand-side bidding to secure those savings.

Under Ontario Hydro's incentive programs, municipalities, universities, hospitals and schools (the MUSH sector) were a target market for energy service companies to install energy efficient equipment and load control systems. The MUSH sector is expected to be a prime candidate for aggregators when the statutory price expires.

Load serving entities offer more opportunity for load aggregation

A wider definition of aggregator changes the focus and opportunities for load shifting and shedding. Most restructured markets in the United States include the concept of a Load Serving Entity (LSE): a utility with the obligation to serve "native load", including procurement of supply, transmission rights, distribution, planning and contracting resource adequacy. The LSE can meet its obligations by using bilateral contracts, the day ahead and real time energy markets. LSEs act as load aggregators for all loads in their service area that have not secured alternative supplies through retail or wholesale contracts. The Ontario model is different; the concept of distributors acting as LSEs was not incorporated in the market design. In Ontario, the Distributor has an obligation to provide standard supply service but no authority to procure energy or other services.

California experience

The California Independent System Operator (CAISO) has operated a demand response program - the Participating Load Program (PLP)- since the crisis period. This program allows demand curtailment from aggregators to substitute for some ancillary services. The CAISO adopted a very broad definition of aggregator:

> "It is important to understand the definition of a load aggregator. Load aggregators, for the purpose of this program, may be a single load, a municipality or other governmental entity, an Energy Service Provider (ESP), a Scheduling Coordinator (SC), a Utility Distribution Company (UDC), or any other entity representing single or multiple Loads for the purpose of providing Demand reduction service to the ISO."[13]

In combination with two other programs, the Demand Relief Program (DRP) and Discretionary Load Curtailment Program (DLCP), the PLP showed some promise, producing 1,100MW of demand response. However, regulatory concerns[14] resulted in the development of new, non-CAISO programs that limited participation. Using a narrow definition of aggregation (as the California PUC appears to have done in excluding interruptibles and investor owned utilities), then the total program is the DRP and DLCP, the latter being closest to true aggregator demand-side bidding. In July 2001, these programs amounted to 162MW and 22MW respectively.[15]

New York experience

The NYISO operates a similar set of schemes - Emergency Demand Response Program (EDRP) and the Day-Ahead Demand Response Program (DADRP). End-users participate in the programs through an intermediate aggregator, such as a utility, retail electricity provider, or curtailment service provider. All six of New York's investor owned utilities participated as aggregators in the NYISO programs. Some of the smaller retailers, e.g. Energy Analytics, Strategic Energy, and Econnergy (which can reasonably be classed as aggregators) are registered to participate in the scheme but their contribution to date has been small.

7 NEXT STEPS

The success of efforts by large and small consumers in response to the recent power emergency shows the potential for DSM and DR. This potential needs to be organized as a predictable resource.

7.1 Phase II Consultation

Options for policy framework

This paper provides a springboard for further work by a stakeholder consultations. Amongst other matters, consultation will explore and formulate, with input from stakeholders, options regarding a policy framework to facilitate DSM and DR in Ontario's energy markets including recommendations as to why, what, when and how a distributor might contribute.

7.1.1 Stakeholder Representations

Stakeholder input

Stakeholders will be invited to identify options, describe who is involved in the various stages of DSM and DR implementation (identifying objectives and opportunities, funding, design and delivery, and monitoring and evaluation) and identify the elements of the sector foundation that would have to change to remove barriers and allow DSM and DR activity.

7.1.2 Stakeholder Advisory Group Discussions

Advisory group work

A stakeholder advisory group will work with Board staff to build on stakeholder ideas and explore and formulate specific options regarding the policy framework needed. The group will discuss alternative options along with appraisal of advantages and disadvantages in the Ontario context. Analysis will be made of experience in Ontario to date and in other jurisdictions, with extensive discussion of how these experiences may translate into effective policy for Ontario going forward. Consideration will be given to the issues outlined in Chapter 3 of this paper.

7.2 Phase III Consultation

The analysis and recommendations coming out of the Phase II consultation will help the Board prepare its draft Report of the Board. Stakeholders will have the opportunity to review and comment on the Board's draft report.

7.3 Report to The Minister

The Board will finalize its Report to the Minister after considering stakeholder comment on the draft.

Implementation details will be finalized in appropriate regulatory process

Implementation details of the preferred DSM and DR framework to support any recommended role for distributors will be finalized through the development of guidelines in the appropriate regulatory process. In the case of electricity distributors, this will be the development work for second-generation performance-based regulation (PBR II), and/or amendment of codes. In the case of gas distributors, the Board will decide at a later date whether to develop these guidelines in a generic proceeding or in the companies' individual rate cases.

APPENDICES

A Overview of Ontario Gas And Electricity Sectors

1 Electricity Sector

Electricity Sector

Brief History

Advisory Committee on Competition in Ontario's Electricity System

In late 1995, the Government authorized the appointment of an advisory committee, (the Advisory Committee on Competition in Ontario's Electricity System, Chaired by the Honourable Donald S. Macdonald), to study and assess options for phasing in competition in Ontario's electricity system. In May, 1996, the committee issued its recommendations to the Ministry, which included the break-up of Ontario Hydro and the restructuring of the electricity sector.

Government white paper

In November, 1997, the Government announced its proposal for restructuring Ontario's electricity system, including the break-up of Ontario Hydro, in its White Paper entitled "Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario." In the paper, the Government presented a plan for introducing full competition into Ontario's electricity system in the year 2000. It recognized that new opportunities were emerging as the North American electricity industry changed from one based on monopoly to one based on competition. Ontario needed to restructure its electricity industry in order to create a business climate to support new technologies, new services, and new ways of doing business.

Electricity market design committee

In January, 1998, the Government established the electricity Market Design Committee to advise on market rules and the structure of Ontario's competitive electricity market to be created under what is now the *Energy Competition Act, 1998*. The committee submitted its final report at the end of January, 1999.

Ontario Energy Board Act, 1998

The *Ontario Energy Board Act, 1998* (OEB Act) provides the Board with guiding objectives, licensing authority, and choices in rate setting methodologies in its regulatory oversight of the electricity sector.

On May 1, 2002, the Ontario electricity market opened to both wholesale and retail consumers.

Tight supply a concern; greenhouse gas reduction a concern

Tight electricity supply and the need to reduce greenhouse gas emissions[16] are concerns in Ontario. The province is working to balance demand- and supply-side solutions. In Ontario, an all time high peak of 25,496 MW was reached in August, 2002. Throughout the summer there were alerts from the Independent Electricity Market Operator (IMO) asking consumers to reduce their demand. The highest winter peak was 24,158 MW, set on January 22, 2003. The Market Surveillance Panel's October 7, 2002 report concluded that there is a serious capacity shortage in Ontario. While the August 14, 2003 grid outage was not due to a shortage of supply to the province, it did communicate the importance of curtailment and conservation to energy users.

Overview of the Electricity Sector

Before looking at the issues around implementation of DSM and DR, it is important to understand the current foundation and how it constrains participation by significant portions of the electricity sector.

Foundation for the market

1.1 Foundation

The underlying foundation of the electricity sector in Ontario defines how the market operates and how stakeholders interact. It is built on principles developed by the Market Design Committee and developed by the IMO, laws and regulations passed by the government of Ontario and to a lesser degree by the federal government, rules prepared and adopted by the IMO and regulatory instruments and decisions issued by the Board.

This foundation binds participants and may form a barrier to DSM/DR activity; e.g., a distributor cannot provide energy management services to a large consumer because it is prevented from engaging in competitive activities. A retailer may not be able to aggregate load for a demand bidding program because some consumers cannot, even with the necessary technology, respond to 5-minute dispatch intervals established by market rules. The following sections describe the foundation and how it applies to various participants to provide background to future discussions of barriers.

1.1.1 Market Design Principles

Design principles

In 1997, the Ontario government released a White Paper (*Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario*, November 1997) outlining the need to restructure the electricity industry. The White Paper set objectives and identified key elements of a restructuring plan. The Market Design Committee (MDC) originally developed the principles and market design for the wholesale market. The MDC submitted a four-volume report to the Minister of Energy. The final report contained recommendations on market design and the types of rules, institutions and regulatory framework required to achieve the restructuring goals.

1.1.2 Legislation and Regulation

Legislation and regulation

The Ontario Government developed two primary pieces of legislation to put the market design in place: *The Electricity Act, 1998* and its revisions and regulations (Electricity Act) and the OEB Act and its revisions and regulations.

1.1.3 Market Rules

Market rules

The Independent Electricity Market Operator (IMO) is established under the Electricity Act and given authority to make Market Rules. The IMO has devised a three-part hierarchy of rules and operating procedures: the Market Rules, Market Manuals and technical interfaces. In December, 2002, the *Electricity Pricing, Conservation & Supply Act, 2002*[17] was passed. In it written approval of the Minister is needed for any Market Rule change.

The IMO has a Market Advisory Committee to provide input to overall market development, various Technical Committees to recommend Market Rule changes and a Board of Directors for final approval of changes. Any person can appeal Market Rules and amendments to the Ontario Energy Board. An independent panel of the IMO, the Market Surveillance Panel, is responsible for overseeing the market and reports directly to the IMO Board.

The Board licenses the IMO and reviews and regulates the IMO's budget and charges to recover costs. Through the *Electricity Pricing, Conservation & Supply Act, 2002*, the wholesale market service charges are frozen until May 1, 2006, unless an application to change the charge is approved by the Minister.

1.1.4 Regulatory Instruments

The OEB's tools in electricity

Pursuant to section 57 of the OEB Act, many participants in the Ontario electricity industry are licensed by the Board: distributors, transmitters, certain generators, retailers, wholesale market purchasers, wholesalers, and the IMO.

Licences and codes

In 1999-2000, the Board, with the help of industry task forces, developed the licences and codes of conduct and operation that constitute the Ontario licensing regime. These regulatory instruments set the requirements, standards, terms and conditions of electricity market participants' legislated obligations. These codes include:

- *Transmission System Code* - sets rules for the operation of transmission systems;
- *Affiliate Relationships Code for Electricity Distributors and Transmitters* - specifies the relationship between the distributor or transmitter and its affiliates in competitive markets;
- *Distribution System Code* - sets rules for operating distribution systems;
- *Retail Settlement Code* - sets rules for settlement between the Distributor, consumers and retailers and sets standards for electronic business transactions; and
- *Standard Supply Service Code* - rules for how standard supply service is to be billed and settled.

Guidelines

The Electricity Distribution Rate Handbook sets guidelines for how distribution rates are to be determined.

The Board has since added the *Electricity Reporting and Record-keeping Requirements* that specifies information that distributors, transmitters, retailers, wholesalers and generators must report to the Board.

The final form for licences is under development. New, long-term licences for distributors, generators and transmitters should be issued by the end of 2003.

Determination of rates

The Board, through hearings, also determines regulated rates for the IMO, transmitters and distributors. Through the *Electricity Pricing, Conservation & Supply Act, 2002* rates for the IMO, transmitters and distributors are frozen until May 1, 2006 unless the Minister approves a request for a rate hearing under section 79.6 of the OEB Act.

1.2 Participants

Sector participants

The term “Market Participant” is defined in the Market Rules. Not all participants in the electricity sector are Market Participants.

1.2.1 Generators

Generators

The Board licenses all generators who sell electricity or ancillary services in the wholesale or retail markets. Co-generation plants and self-generators are excluded from this licensing requirement unless they sell a portion of their generation. Generators who sell in the wholesale market or are dispatched by the IMO must register as market participants with the IMO, comply with the Market Rules, and act according to the Market Manuals and technical interfaces. They are also constrained by Ontario’s environmental laws and dependent regulations such as the Environmental Protection Act, Water

Resources Act, Environmental Assessment Act (if applicable), and Planning Act (if applicable). Some Federal laws also affect generators including the Environmental Assessment Act and the Environmental Protection Act. Other requirements are specific to the power source. Some Federal regulations govern water use and nuclear generating station licensing and operations.

Currently, Ontario Power Generation owns and operates approximately 75 per cent of the generation in Ontario with base, intermediate and peaking facilities. Imports provide up to 10 per cent of capacity at peak periods. By government directive, OPG's licence includes sections of the Market Power Mitigation Framework (MPMF) that set decontrol targets for peaking and total generating capacity and require OPG to make rebate payments to consumers under specific market conditions. The government can issue directives to the Board under section 28.1 of the OEB Act to change the licence conditions derived from the MPMF.

Generators participating in the real-time energy market operated by the IMO offer energy into the market in a detailed schedule of price – quantity pairs. The IMO determines least cost market schedules and arranges settlement for energy and ancillary services. Some generators (e.g. energy resource limited, intermittent or under 5 MW) are self-scheduling; i.e., they are not subject to bidding or dispatch but generate as they can, when they can. Generators must coordinate their planned outages through the IMO.

When congestion occurs in the transmission network, the IMO will take into account the physical limitations of the system to produce a "constrained" dispatch schedule. In the dispatch schedule, high-cost generation will be substituted for low-cost generation to alleviate the congestion. This results in a higher cost of generation than the least cost market schedule.

Currently, the cost of this re-dispatch is spread across all customers in an "uplift charge" to maintain a province-wide uniform price. Under locational marginal pricing (LMP), energy prices would differ from place-to-place when congestion forces a re-dispatch of generation. LMP is meant to reflect the real-time marginal cost of supplying energy at specific points on the network and has been adopted by several market-based electricity systems in North America and elsewhere.

1.2.2 Transmitters

Transmitters

The Board licenses transmitters and sets transmission rates through an application, hearing and decision process. There are 5 licensed transmitters in Ontario. Through the *Electricity Pricing, Conservation & Supply Act, 2002*, Transmission rates are currently frozen until May 1, 2006, unless the Minister grants specific permission for an application to the Board.

Transmitters must apply to the Board for leave to construct certain transmission projects through Section 92 of the OEB Act. By licence condition, transmitters must abide by the *Transmission System Code* and the *Affiliate Relationships Code for Electricity Distributors and Transmitters*.

Transmitters must register as market participants with the IMO and give the IMO operational control of their transmission system. The IMO does system evaluations and establishes the need for new facilities to ensure reliability. System outages must be planned and coordinated with the IMO. The IMO can overrule transmitter requests for outages if it is necessary to maintain system reliability. Currently, Hydro One Networks Inc. owns over 90 per cent of the high voltage transmission network in Ontario and virtually all connections to other regions.

1.2.3 Distributors

Distributors

The Board licenses distributors. Distribution rates are regulated and currently frozen by the *Electricity Pricing, Conservation & Supply Act, 2002* until May 1, 2006, unless the Minister permits an application to the Board.

Through licence conditions, distributors are required to comply with the Affiliate Relations Code for Electricity Distributors and Transmitters, the Distribution System Code, the Retail Settlement Code, and the Standard Supply Service Code (SSS) Code.

The SSS Code has been superceded largely by legislation and regulations that set statutory prices for low volume and designated loads. Although distributors have an obligation to provide SSS, the intent of the retail market design was to have distributors act as “pass through agents” for energy load and prices, without assuming a procurement role and the attendant financial and load forecasting risks. This design was expected to open the market to retailers, brokers and aggregators who are able to assume market risks more readily than distributors. This differs substantially with the concept of utilities acting as Load Serving Entities (LSE) with responsibilities for securing energy supply, ancillary services, and/or reserve capacity.

Restriction on business activities of transmitters and distributors

Section 71 of the OEB Act provides that transmitters and distributors may not carry on any business other than transmission, distribution or provision of SSS except through an affiliate. Section 72 requires distributors to keep their financial records associated with distribution separate from their financial records with respect to other activities. Again, this was intended to make distributors wires-only businesses with no role in the competitive markets.

Before market restructuring, distributors had an "obligation to serve". Now there are two specific statutory obligations. Section 28 of the Electricity Act obligates every distributor to connect a building if the building owner wants to be connected and if the building is along the distributor's lines. Section 29 of the Electricity Act obligates every distributor to provide SSS to any consumer connected to its system. A consumer may advise the distributor in writing that it does not require this service. Most distributors are wholesale market participants and subject to IMO Market Rules.

There exists a variety of size and situation across distributors

While significant electricity distribution sector rationalization has occurred since the development of the original draft PBR plan for electricity distributors in 1998, there still exists a variety of size and situation in the remaining 95 licensed distribution companies. Hydro One continues to serve over 1 million customers. The balance of distributors range in size from under 200 to over 500,000 customers, with two distinct clusters: 22 distributors have between 1,000 and 6,000 customers, and 37 distributors have between 10,000 and 26,000 customers. Many of the electricity distributors have established affiliates through which they carry out a number of competitive activities, including the sale of electricity and the rental of hot water heaters. However, some of the electricity distributors have divested themselves of part, or all competitive business.

A distributor that receives supply from another distributor may or may not be a Market Participant; however, the majority are.

1.2.4 Energy Service Providers

Energy service providers

Energy Service Providers are private sector companies who offer energy-oriented, value added services to consumers. These services may include procurement, fixed price certainty (i.e., retail services), and energy management services including load control, and efficiency savings through capital replacement and conservation targets (e.g., through energy audits, HVAC retrofits and control, process efficiency studies... etc).

1.2.5 Network and Meter Service Providers

Network and meter service providers

Network and meter service providers offer technology and operation support on contract. Their services are on a competitive fee basis. Network services may include design and construction, operation, maintenance and restoration, scheduling, and work management responsibilities to service distribution or transmission facilities. Meter services may include the meter installation, administration, reading, data management and maintenance.

1.2.6 Wholesalers

Wholesalers

Wholesalers are Market Participants who are purchasing energy and/or ancillary services for resale to retailers. They are licensed by the Board and registered as Market Participants.

1.2.7 Retailers

Retailers

The Board licenses retailers. They are bound by licence conditions to follow the RSC and the *Electricity Retailer Code of Conduct*. There are 71 licensed retailers in Ontario; not all are active.

Retailers have contracts to supply retail consumers who have elected not to receive SSS. Retailers may or may not also be Wholesalers.

Sections of the OEB Act and dependent regulations with respect to consumer protection and contracts apply to retailers. Retailers are also subject to the *Consumer Protection Act* (ON).

The legislation that set a statutory price for low volume and designated consumers provides that where the market price is less than a retailer's contract price with the consumer, the Ontario Electricity Financial Corporation (OEFC) will pay the retailer the difference, funnelled through the IMO and the distributor.

1.2.8 Consumers

Consumers

Market Participants (Purchasers)

Wholesale market consumers

Consumers who are Market Participants are primarily large industrial consumers that purchase electricity in the wholesale market for their own use. Consumers who are directly connected to the IMO-controlled grid must be Market Participants. Relatively few large consumers who are not connected to the IMO-controlled grid are Market Participants. The Board licenses consumers who wish to be Market Participants as Wholesalers. By December, 2002, there were 90 wholesale consumer/end-use consumer organizations participating in the Ontario electricity market[18].

Consumers who are Market Participants are required to abide by the IMO's Market Rules, including prudential support and settlement. All Market Participants settle at the Hourly Ontario Energy Price (HOEP) and must have a meter that measures consumption on an hourly basis, at a minimum. The Market Rules have additional metering standards.

Retail consumers (commercial, industrial, or residential)

Retail market consumers

Retail consumers have their electricity delivered to them by distributors. Nearly all retail consumers have unbundled rates for fixed and volumetric distribution charges, transmission charges and energy. Retail consumers may be commercial, industrial or residential consumers. Some commercial and industrial consumers may have load large enough to consider wholesale market participation, but remain retail market participants. All retail consumers may sign up with a retailer or may remain on SSS with their distributor.

Low volume (consumption of less than 250,000 kWh per year or demand of less than 50 kW) and designated consumers (universities, schools, hospitals, charities etc.) had their commodity price fixed until May 1, 2006 at $43 per megawatt hour (MWh) by legislation and regulation passed in late-2002.

1.2.9 Ontario Electricity Financial Corporation (OEFC)

Ontario Electricity Financial Corporation

By regulation, when the market clearing price is greater than the statutory price, the OEFC refunds to distributors (or retailers) the difference between the $43/MWH charged to a low volume or designated consumer and the market clearing price paid by a distributor to the IMO for settlement with the Generators. In cases when the market clearing price is lower than the statutory price, distributors remit the difference to OEFC through the IMO. The OEFC also pays retailers the difference between the contract price and the HOEP price if the contract price is higher.

2 Evolution of Competition in the Gas Sector

Gas Sector Evolution

In 1985, the governments of Canada, British Columbia, Alberta and Saskatchewan signed the "Agreement on Natural Gas Markets and Prices" (The 1985 Agreement). The objective of the agreement was to end the regulation of wholesale natural gas prices and create a competitive market where buyers and sellers could freely negotiate those prices.

Unbundling of gas utility services

In Ontario, business practices evolved over time to enable this agreement. The Ontario Energy Board (the "Board") supported the development of the competitive market for natural gas and facilitated a competitive direct purchase market by addressing the unbundling of gas utility services, and establishing contract carriage service (T-service) with a "buy/sell" mechanism. In its determinations, the Board:

- found that agents, brokers, and marketers (ARMS) were "suppliers of gas" within the meaning of the existing legislation;
- accepted new methods to achieve out-of-province title transfers;
- dealt with the potential double recovery of Unabsorbed Demand Charges; and,
- facilitated "buy/sell" transactions so that the benefits of competition could be made available to a broader customer base.

Security of supply issues addressed in 1988

In the late 1980s, the Board assessed the Ontario gas utilities' renegotiated long-term gas supply contracts with TransCanada Pipe Lines (TCPL) and the prudence of the associated gas costs. In 1988, the Board made recommendations to the Government of

Ontario with respect to security of supply issues such as the need for a portfolio approach to gas-supply contracting; securing appropriate transportation contracts; and, rejecting different security requirements for different segments of the market.

"Minimum Conditions of Supply" negotiated

In August, 1991, Union Gas Limited (“Union”), The Consumers’ Gas Company Ltd, and Centra Gas Limited (“Centra”) expressed concern to the Minister of Energy over the growth of direct purchase and its impact on security of supply. The Minister requested that the gas utilities and representatives of the direct purchase market negotiate conditions of supply. The negotiations were captured in a "Minimum Conditions of Supply" report and presented to the Minister in April, 1992. The Minister supported the conditions and the gas utilities began to implement them that summer. In the spring of 1993, several parties approached the Board with concerns over implementation of these conditions and their consequent impact on the direct purchase market. A workshop was convened to address:

- the implementation of minimum conditions of supply;
- policies regarding the return to system supply;
- buy/sell pricing; and,
- buy/sell terms and conditions.

Board convened proceeding over implementation of the conditions of supply

The Board convened a proceeding to consider these issues in the summer of 1993. The Board's Decision was released in April, 1994, and in it the Board indicated that it preferred the industry negotiate solutions to the issues. To assist these negotiations, the Board provided its views on the issues and associated matters in its Decision. Industry negotiations continued throughout 1994 in what became known as the Direct Purchase Industry Committee (DPIC).

10-year market review

In the 1995 Centra Gas Ontario Inc. rates decision, EBRO 489/EBRLG 34-14 Decision with Reasons - Part II, the Board recognized that regulating the utility's gas costs, based on annual rate adjustment principles in an environment of indexed and volatile commodity prices was problematic. The Board initiated a forum to review the workings of the market and the separation of commodity sales from the other functions within a gas utility. Known as the ten-year market review (TYMR), forum participants identified legislative concerns; market imperfections; and, gas utility market dominance as issues.

The TYMR Report issued by the Board, dated September 27, 1996, identified the legislative prohibition against gas sales by any person other than a gas utility in Ontario as a concern. Some TYMR participants provided a list of necessary market conditions, including the ability to switch suppliers, which the Board accepted. The Board concluded that competition was preferred to economic regulation and that there was need for further deregulation, transitional customer education regarding utility supply, and a code of conduct to govern the relationship between a gas utility and its marketing affiliate. However, legislation did not endow the Board with sufficient authority to implement the required changes.

A Working Group on Natural Gas Markets (the "Working Group") was formed in the fall of 1996. It delivered its report to the Board in May, 1997. The Working Group agreed that legislative change was required to enable gas commodity title transfer in Ontario, and that the Board should not regulate markets which are subject to full and effective competition. The report of the Working Group identified long-term goals including a market structure which allowed full and effective competition at the burner tip; customer mobility between gas marketers; and, customers being able to choose from whom they receive their bill. However, the Working Group could not reach consensus on how to effect these changes to achieve these goals.

Agency Billing and Connection (ABC) service introduced

Also in 1996, in response to market demand and the introduction of new billing technologies, Agency Billing and Collection (ABC) service was introduced; it allowed ARMS to bill their customers directly through the gas utility.

Advisory Report to the Minister on Legislative Change Requirements for Natural Gas Deregulation

In 1997, following a public consultation, the Board advised the Minister on legislative change to the Ontario Energy Board Act. The Board's Report is titled: "" and is dated December 16, 1997. The Board's intentions were to improve the effectiveness of regulation and to enable the regulator to deal with market imperfections. The report commented on the benefits of rule-making as enabling less prescriptive legislation and therefore accommodating change in government policy; promoting consistency in regulatory treatment; facilitating regulatory efficiencies; and, providing greater flexibility to implement specific practices and procedures. The report also recommended that gas commodity title transfer be enabled in Ontario; that regulation of monopoly functions continue; that a licensing scheme be established; and, that consumer protection and education be strengthened.

Code of Conduct to Govern the Relationship of the Utilities with Affiliate and Independent Gas Marketers

After a hearing into affiliate matters and gas marketer relations with gas utilities, in May, 1997, the Board required the gas utilities to comply with the "Code of Conduct to Govern the Relationship of the Utilities with Affiliate and Independent Gas Marketers"[19] which addressed:

- the physical, organizational and financial separation of the gas utility business and its marketing affiliate;
- the sharing of resources between the gas utility business and its marketing affiliate;
- equitable access to utility services;
- a prohibition on the preferential treatment of affiliates and limitations on the provision of information;
- a prohibition on preferential endorsements;
- employee compliance; and,
- a complaint process.

Market Design Task Forces

The Board established the Market Design Task Force ("MDTF") in 1998 following the announcement by the Ministry regarding new legislation to improve the efficiency of competition in energy markets, and the restructuring in the electricity market. The MDTF advised the Board on the implementation of preferred policy options to further enhance competition in the sale of gas. The MDTF recommended further unbundling and regulatory reform to generate customer benefits. It also identified that the Board should define regulatory boundaries; explore new regulatory instruments; seek new ways to interface regulated and unregulated activities; and, focus on the outcomes of, rather than detailed inputs to, gas utility regulation. The MDTF was concerned about the treatment of existing contractual obligations during transition periods, and proposed customer education as a component of any change. The MDTF membership did not agree on all of the recommendations and suggested that there was a need for a mechanism whereby the Board could provide direction on an expedited basis. Since the MDTF could not agree on how to effect the transition to such a structure, it suggested that the Board provide the direction.

A second Market Design Task Force ("MDTF2") was established. It echoed the first MDTF's views on the benefits to customer choice in gas commodity supplier; however, it too could not agree on how to implement that choice during the transition to the needed end-state market structure.

OEB Act

The OEB Act allows for further deregulation in the natural gas commodity market (for example, the transfer of title to gas in the province). It also provides the Board with guiding objectives, rule-making authority, and choices in rate setting methodologies in its regulatory oversight of the gas sector.

Unbundling of gas services incremental

Union and Enbridge have been unbundling incrementally. Gas commodity costs were unbundled shortly after the 1985 Agreement was signed. Gas transportation rates were unbundled upon the availability of increased pipeline capacity and TransCanada implementing a turn back policy. Further unbundling is anticipated as competition in gas transportation may be enhanced by enabling choice in gas storage.

2.1 The Natural Gas Market

Natural Gas Market

Gas prices determined by competitive forces of supply and demand

Natural gas prices in the producing regions of North America are determined by the competitive forces of supply and demand. The short-term, or spot price, fluctuates daily due to several factors including weather and short-term disruptions. For instance, a hurricane in the Gulf of Mexico, or a snap deep freeze in Western Canada, two of the largest gas producing regions, can affect the short-term price of natural gas.

Longer term gas prices are determined by population and economic growth, and by factors such as environmental policies. For example, greater demand for gas as an environmentally-preferred fuel for electricity generation could result in increased gas prices.

Gas supply

Ontario obtains some 93 percent of its gas supplies from the western Canadian provinces through the TransCanada PipeLine Limited interprovincial pipeline system and related systems. The province also imports about 5 per cent from the United States and produces approximately 2 per cent itself.

Gas distributors

There are three local distribution companies distributing natural gas in Ontario that are rate regulated by the Ontario Energy Board: Enbridge Gas Distribution Inc., Union Gas Limited and Natural Resource Gas Limited.

In addition to the three that the Board regulates, there are five small gas companies and two municipally owned gas utilities (City of Kitchener and City of Kingston) that are exempt from rate regulation by the Board but are bound to Board approved Rules.

Ontario gas consumers

Approximately 50% of Ontario gas consumers continue to purchase their gas from gas distributors, while the remaining 50% purchase from gas vendors or gas marketers.

Regulation of Natural Gas

2.2 The Board's Role in the Regulation of Natural Gas

Gas utility rates

The Board approves natural gas rates charged by the gas utilities, as well as approving pipeline construction, the terms and conditions of franchise agreements, certificates of public convenience and necessity, storage facilities and utility ownership changes. The Board also licenses gas marketers wishing to retail natural gas to residential and small commercial consumers.

System gas rates

For those customers who purchase their gas directly from the local gas distributor, rates also cover the commodity cost of gas passed through to the customer without markup.

Pipeline construction

OEB approval is required to construct a natural gas transmission line in Ontario.

Certificates of public convenience and necessity

Board approval, in the form of a Certificate of Public Convenience and Necessity, is required to construct any works to supply gas in Ontario. Approval is granted only where public convenience and necessity support the extension of the service.

Storage

Natural gas may be injected into a geological formation in Ontario only where land is designated by the Board. The Board may authorize a storage area's use.

Licensing of gas marketers

Effective March 1, 1999 companies wishing to sell natural gas to low-volume consumers (residential and small commercial customers consuming less than 50,000m3 of gas per year) or to act as an agent in the sale of natural gas in Ontario are required to obtain a licence from the Ontario Energy Board. These gas marketers are bound, though the licence, to comply with the Code of Conduct for Gas Marketers. There are 32 licensed gas marketers in Ontario; not all are active.

B History of DSM in Ontario Electricity and Gas Sectors

1 DSM in Electricity

Ontario Hydro's DSM efforts in the 1980's and 1990's

1990 savings reported by Ontario Hydro due to DSM amounted to 220 MW

Ontario Hydro formalized its DSM efforts in the 1980s, culminating in a major 25-year plan filed as part of its Demand-Supply Plan (DSP) in 1990. Throughout the late1980s and the early 1990s, the Ontario Energy Board reviewed Hydro's DSM plans and supported the utility's direction. The plans contained programs targeted to the residential, agricultural, commercial, and industrial market sectors. The programs were designed to provide ways for customers to control their bills by installing energy-saving measures, by flexible financing or incentives for making those improvements, by working with the marketplace to ensure that such products and equipment were widely available, and by providing information and guidance about energy use. For example, in the commercial and industrial sectors, programs included audits to identify opportunities and a combination of information and incentives programs to increase awareness of new efficiency technologies (e.g., lighting and high efficiency motors) and reduce technical barriers. While some programs were targeted directly to the consumers, others such as the "Savings by Design" program were primarily targeted to consulting engineers, architects and developers of new construction as well as building owners and managers of existing buildings. Audits, information and incentives were also offered in the residential and agricultural sectors. The technologies promoted in these sectors included heat pumps, windows, water heaters, and lighting. Standards promoted included R2000 in the new home market[20]. In 1990 Ontario Hydro's DSM activities generated net annual system savings of approximately 220 MW[21]. In its H.R. 20 Report of the Board, the Board noted that in 1992, Ontario Hydro's load saving and shifting target was "increased substantially as a result of government directives to [the company] to increase its efforts in energy management. The updated budget expenditures were over C$300 million."[22]

Municipal Electric Utility involvement limited

Municipal Electric Utility (MEU) participation was limited compared to that of Ontario Hydro; however, several MEUs cooperated with Ontario Hydro, or acted independently, in the promotion and delivery of DSM.

Ontario Hydro involvement in DSM declined throughout the 1990's

Hydro withdrew its DSP (in part due to lower load forecasts) in the early 1990s.

In 1994, Ontario Hydro formed an "Internal Energy Efficiency Support Group" to accelerate internal energy savings. In the Ontario Hydro H.R.22 proceeding, the company reported that the in-house program was under development. At the same proceeding, the company presented its 1995 Energy Management Programs DSM portfolio, designed with a target market focus and with less reliance on incentive programs. However, the following year, in the H.R.23 proceeding, deliberation regarding energy efficiency focussed on commitment to energy efficiency in optional rates. The DSM portfolio and related programs, per se, were not discussed.

"... a better understanding of all the issues surrounding DSM is needed..."

Electricity distributor involvement in demand-side management (DSM) was considered by the Board in 1999 during the RP-1999-0034 proceeding on Board staff's Proposed Electric Distribution Rate Handbook for licensed electricity distributors. In its January 18, 2000 Decision with Reasons, the Board found that a better understanding of all the issues surrounding DSM is needed before DSM principles, programs and mechanisms can be incorporated into a PBR regime for the electricity distribution industry[23]. While the Board identified the need for a better understanding of the distributor's role in DSM, it expressed an expectation that distributors continue existing DSM programs and furthermore they should offer new programs, if they could be established cost-effectively under the distributor's rate plans.

2 DSM in Gas

OEB generic hearing into least cost planning in gas (E.B.O. 169) begins in 1990

In April, 1990, the Board called a generic hearing into least cost planning (LCP; also referred to as integrated resource planning - IRP), and an issues list was released for consultation in September of that year. The proceeding, E.B.O.169, formally began in September, 1991 with the issuance of a Board staff discussion paper entitled, "Report on Gas IRP" and a Notice of Hearing. The proceeding spanned 3 phases over a 2-year period.

Phase I, in October, 1991 gathered written comment on staff's discussion paper.

OEB decided to focus on DSM first

Phase II, commenced in May, 1992, when the Board announced its "building block" approach to dealing with IRP, and that it would focus its efforts first on DSM. Consideration of supply-side issues were to follow at a later date (proceeding E.B.O.188) once the demand-side issues were vetted. Phase II provided for technical conferences (August and September) that culminated in finalized consensus positions in October, 1992.

Board endorsed formalized DSM planning by east of the major gas utilities in Ontario

Phase III, the oral hearing, held over November and December of 1992, resulted in the July, 23, 1993 Report of the Board (E.B.O. 169-

III). In it, the Board endorsed the need for formalized DSM planning by each of the major gas utilities in Ontario. As a result, the Board issued guidelines to assist the utilities in the development and implementation of their DSM plans. These guidelines address the 11 major DSM-related issues identified by stakeholders in the two technical conferences leading up to the formal proceeding:

OEB issued guidelines that addressed 11 major DSM-related issues

- appropriate costing methodology for demand-side options;
- cost-effectiveness tests;
- treatment of externalities;
- consultation on externalities;
- regulatory treatment of DSM investments;
- allocation of DSM costs;
- incentives and decoupling mechanisms;
- monitoring and evaluation;
- rate design and DSM;
- jurisdictional concerns; and,
- implementation of DSM.

Significant Highlights of the E.B.O.169-III Report:

Other highlights from the E.B.O. 169-III Report of the Board

- In its decision, the Board recommended that "government consider: regulation to establish carbon dioxide emission targets; further development of standards and fiscal measures to improve energy efficiency; establishment of a regulatory mandate for IRP; and, clarification of the roles of government agencies to effectively coordinate IRP in all energy sectors." (E.B.O. 169-III, executive summary)

- In considering an appropriate costing methodology, the Board determined that long-term avoided supply-side costs should be used, and that these long-term investments should be included in rate base.

- In considering regulatory treatment of DSM investments, the Board's guidelines suggested "that DSM efforts should be included as part of utility operations and not "spun-off" as a non-regulated affiliated business." (E.B.O. 169-III, para. 15.1.8)

Shared savings (SSM) and lost revenue adjustment mechanisms (LRAM)

- In considering incentives and decoupling mechanisms, the Board did not see a need to require utility incentives or decoupling at the time. However, the Board's guidelines suggested that "if utility incentives are shown to be required, shared savings, based on the nature or urgency of the program, the market being targeted and the degree of difficulty in program implementation, should be viewed as the preferred approach to the provision of incentives." (E.B.O. 169-III, para. 15.1.10) The guidelines also suggested that "if a utility considers that a lack of revenue protection is a significant disincentive, it may propose a revenue adjustment mechanism, provided that the impacts that the mechanism has on the utility's risk exposure and earnings are also considered. (E.B.O. 169-III, ibid)

- In considering implementation, the Board suggested that the "utilities should take advantage of DSM delivery mechanisms, such as those available from [Energy Services Companies] ESCOS" (E.B.O. 169-III, para. 15.1.14), and that "where appropriate, programs should be designed to consider all energy conservation opportunities, rather than just focussing on natural gas conservation measures in isolation." (E.B.O. 169-III, ibid)

Subsequent decisions dealt with SSM and LRAM

In later decisions, the Board authorized the use of shared savings (SSM) and lost revenue adjustment mechanisms (LRAM). In Union's E.B.R.O. 493/494 Decision in March 1997 the Board was not persuaded of the need for an LRAM or an SSM at that time. In the Board's decision concerning Enbridge Consumers Gas in E.B.R.O. 495 in 1997, an LRAM was authorized to keep the company whole; however, the Board was not prepared to approve the introduction of an SSM at that time. In the Enbridge proceeding E.B.R.O. 497-01 in November 1998, parties settled on an SSM which the Board accepted subject to updates being required for other aspects of the Board's decision or "unforeseen events". In the Union E.B.R.O. 499 Settlement Agreement dated November 16, 1998, parties settled on an LRAM which the Board then accepted. There was no consideration of an SSM in the E.B.R.O. 499 Settlement Agreement. Rather, Union agreed to develop a PBR mechanism for DSM and file it as part of its RP1999-0017 PBR application. In the Board's decision regarding Union's PBR application in RP1999-0017, the Board did not approve Union's DSM framework due to an expressed need for a better understanding of energy efficiency in deregulated markets, including the role of the distributor and the role of DSM within the context of a PBR, and lack of agreement among interested parties (particularly regarding the design of an incentive mechanism)[24]. However, it did state an expectation that Union continue its existing DSM programs and only offer new programs if they can be established cost-effectively under its price cap plan.

Major gas utilities' DSM efforts since 1993

Since July 23, 1993, the two major gas utilities in Ontario have managed DSM portfolios within the framework proposed in

E.B.O.169-III. Both have employed the guidelines laid out in the E.B.O.169-III Report to the Board in the planning, valuing and designing, regulatory reporting, implementing, and monitoring and evaluating of those portfolios. The DSM portfolios include programs offered in the residential, agricultural, commercial, and industrial sectors. Similar to those offered by Ontario Hydro in the 1990's (described above), the programs were designed to provide ways for customers to control their bills by installing energy-saving measures, by flexible financing or incentives for making those improvements, by working with the marketplace to ensure that such products and equipment are widely available, and by providing information and guidance about wise energy use.

DSM integrated into company market plans

While E.B.O.169-III sets out specific regulatory requirements related to DSM, both companies have integrated the planning, valuing and designing, and implementation of DSM into their overall market plans.

In 2001, the two major gas utilities reported to have saved 133 million cubic meters of gas due to DSM

In 2001 the two major gas utilities' DSM portfolios, combined, generated net annual natural gas savings of approximately 133 million cubic meters. The direct costs to achieving these savings was approximately C$13 million[25]. For the most part, the programs offered in the early 1990's are still offered by the gas utilities; however, they have evolved as the energy efficient technologies promoted back then have matured in the market and new technologies have emerged.

Stakeholder concern over costs of gas utility DSM rising

DSM issues have intensified in the companies' consultations with stakeholders and in the annual gas distribution rate review proceedings. Incentive mechanisms (specifically LRAM and SSM) have increased the sensitivity of stakeholders to the monitoring and evaluation, and regulatory reporting of DSM program details and results. In Enbridge's RP-2002-0133 Decision, the Board indicated that the DSM framework for all parties within its jurisdiction needs to be reviewed on a broad basis, and that a joint effort by those parties would be helpful to establish common principles and policies.[26]

Board announces examination

The Board has a long history of regulating the activities of natural gas distribution companies and, as noted earlier in this paper, has recently announced that it believes that now is an appropriate time for it to further examine the role of those distributors in DSM.

3 *The Electricity Pricing, Conservation & Supply Act, 2002*

In December, 2002, the *Electricity Pricing, Conservation & Supply Act, 2002*[27] was passed. In it, amongst other matters, the Board's guiding objectives were amended. In electricity, section 1(6) of the *Ontario Energy Board Act, 1998* (the OEB Act) has been changed from "facilitate" to "promote" as follows: "... promote energy conservation, energy efficiency, load management and the use of cleaner energy sources, including alternative and renewable energy sources, in a manner consistent with the policies of the Government of Ontario".

Similarly, in gas, section 2(5) of the OEB Act has been changed as follows: "promote energy conservation and energy efficiency in a manner consistent with the policies of the Government of Ontario".

C Role of Electricity Distributors in Various Jurisdictions

The magnitude of the distributor's involvement in DSM may depend upon numerous factors, including the distributor's demonstrated ability to engineer energy conservation, and the political inclinations of the government or regulatory body. Recent years have witnessed conflicting pressures on DSM with the advent of retail competition worldwide suggesting a decentralized market-based approach, while heightened concern over climate change and natural resource exhaustion has increased calls for a centralized, concerted effort to promote conservation and energy-efficient technologies.

Range of Roles for the Distributor

Distributors may contribute to demand management in a variety of ways. The degree of involvement has considerable implications for the administrative burden faced by regulators and the incentives needed to achieve DSM results. In many jurisdictions, distributors fulfill more than one of six responsibilities:

Six potential roles for a distributor

- No Required Involvement;
- Funds Collection;
- Facilitation and Education;
- Integrated Resource Planning;
- Target-oriented Implementation; and,
- Participation in Demand-side Bidding.

For example, governmental stimulation of research and development of energy-efficient technologies may be funded by a systems benefit charge collected by distributors, while facilitation of, and education programs for DSM are provided by distributors.

The jurisdictions surveyed to date in our analysis of how DSM has been pursued in practice is summarized below. Following the summary, is an examination of the roles played by distributors. Case studies drawn from jurisdictions that illustrate the variation that exists within those roles are summarized below.

Table 2: Summary of Surveyed Jurisdictions[28]

25 jurisdictions surveyed

Jurisdiction	Number of Customers	Total Elec. Sales (MWH)	Status	Regulatory Framework	DSM Funding	Distributor Role
Canada						
Alberta	1,215,579	48,001,400	de-regulated			implementation, demand bidding
British Columbia	1,753,852	49,870,000		PBR OM&A		target-oriented implementation
Manitoba	497,000	22,451,000				implementation
Nova Scotia	442,016	10,656,200				facilitation
Ontario	3,175,485	81,756,000	de-regulated	PBR price cap (RPI-X)	utility discretion under price cap	facilitation, implementation
Quebec	3,505,312	146,989,000				none
Saskatchewan	431,360	17,049,000				facilitation, implementation
United States						
California	12,358,704	221,322,575	de-regulated	PBR price cap (RPI-X)	system benefits charge	target-oriented implementation, demand bidding
Kentucky	2,028,073	78,316,156		PBR earnings sharing		integrated resource planning
Massachusetts	2,960,422	48,862,449	de-regulated		system benefits charge	facilitation, target-oriented implementation
Michigan	4,583,045	104,370,569	de-regulated		system benefits charge	none
Minnesota	2,303,705	59,782,089				target-oriented implementation
New Jersey	3,567,410	62,818,825	de-regulated		system benefits charge	implementation
New York	7,435,514	124,507,669	de-regulated	PBR earnings sharing	system benefits charge	funds collection
Oregon	1,666,035	50,330,414				integrated resource planning
Pennsylvania	5,077,673	98,141,900	de-regulated		system benefits charge	implementation
Vermont	326,438	5,638,614			system benefits charge	funds collection
Washington	2,752,283	93,193,679				integrated resource planning
Wisconsin	2,626,495	65,146,487			system benefits charge	funds collection
International						
Denmark	3,000,000	32,916,000	de-regulated		system benefits charge	integrated resource planning
Finland	3,000,000	81,611,000	de-regulated			none
New South Wales	2,897,000	49,074,000	de-regulated	PBR price cap (RPI-X)		integrated resource planning, demand bidding

Jurisdiction	Number of Customers	Total Elec. Sales (MWH)	Status	Regulatory Framework		DSM Funding	Distributor Role
Norway	2,500,000	110,795,000	de-regulated	PBR	price cap (RPI-X)	system benefits charge	facilitation, implementation
Sweden	5,000,000	128,819,000	de-regulated				none
United Kingdom	24,433,000	266,983,000	de-regulated	PBR	price cap (RPI-X)		none

The survey has concentrated on Canadian provinces and US states since these jurisdictions may be most relevant for Ontario. However, Australia and several European countries have also been investigated. All six roles are represented in the sample, with only the integrated resource planning approach losing popularity in the context of a deregulated environment (with the breakup of vertically integrated utilities), as system oversight is transferred to regulatory agencies and regional transmission organizations.

1 No Required Involvement (Canada, UK, Finland, Sweden)

No required involvement

1.1 Canada

Focus on new technologies and market transformation in Canada

Among the three case studies, the energy efficiency plan overseen by the Canadian federal government is the most oriented toward technological solutions and market transformation. The former are financially supported by the CANMET Energy Technology Centre (www.nrcan.gc.ca/es/etb/index_e.html), which is affiliated with Natural Resources Canada (NRCan, www.nrcan.gc.ca). Through CANMET's contract funding initiatives, approximately C$11 million was made available in fiscal-year 2001 to support the origination and application of energy-efficient and environmentally-responsible technologies throughout the country. Among the recipients of grants were R&D firms engaged in refining existing technologies, construction firms deploying new energy-efficient technology in new and retrofitted buildings, and industrial companies conducting field tests of high-efficiency equipment and machinery. These programs share the costs of developing and installing energy-efficient measures (with CANMET typically shouldering between 35% and 50% of the burden) to help overcome any financial barriers to the creation and adoption of energy conservation technologies.

Programs that promote energy efficient technologies in the market

While CANMET focuses on specific projects, the NRCan's Office of Energy Efficiency (http://oee.nrcan.gc.ca/english/) pursues the longer-term objective of gradually upgrading the energy performance of the nation's residential and commercial buildings. Construction firms are encouraged to voluntarily conform to more stringent standards formulated by NRCan, which have stimulated greater application of energy-efficiency principles by architects and builders, along with the development of new products such as heat recovery ventilators and high-performance windows. NRCan has also recently imported the ENERGY STAR labelling program to promote the gradual replacement of aging appliances with more efficient counterparts. In a sense, all the DSM initiatives undertaken by the federal government are geared toward long-run market transformation, as opposed to more traditional approaches that merely improve energy efficiency one customer at a time.

The two major gas utilities in Ontario provide input into designing and implementing NRCan's Commercial Building Incentive Program (CBIP), and work closely with the Office of Energy Efficiency (OEE) at NRCan. The Design Advisory Program is a joint effort of the two utilities. The program's focus is to promote the development of buildings that meet the standards of CBIP. To encourage the design community, both utilities offer incentive support (up to C$7,800) and pay it directly to a facilitator when an attempt at qualifying for CBIP is made. Facilitators are approved by NRCan, and have received training in the design process necessary to develop energy-efficient buildings.

Distributors further supplement these far-reaching federal efforts by emphasizing outreach to individual customers. Residential programs primarily focus on provision of energy efficiency information. Commercial and industrial business solutions may include equipment incentives and on-site energy audits. Typical measures eligible for incentives in business solutions include higher efficiency boilers; higher efficiency combination water and space heating systems; controls, including Building Energy Management Systems; building envelope upgrades; water conservation; and, efficient make up air.

1.2 United Kingdom

Suppliers (i.e., retailers) responsible for DSM in the UK

In the UK, the distributors' role with regard to DSM was significantly curtailed with the passing of the Utilities Act in 2000. The Act clearly separates the distribution business from the supply business. The suppliers have the responsibility of managing DSM programs on their own. To help customers learn to utilize energy efficiently, many UK suppliers offer education programs as well as information on free services such as home audits or contracting services. Included in these services are educational tips on how to read a meter as well as advice on certain measures to insulate your home without undergoing renovation.

Licence condition

Information-based programs and some government incentives

As a part of their social obligations and licence conditions, all electricity suppliers serving domestic customers are required by the Office of Gas and Electricity Markets (Ofgem) to provide, free of charge, energy efficiency advice upon request as well as bill management assistance for low-income qualifying customers. Furthermore, according to the licence requirements, suppliers must make information available to the customer on obtaining further resources for efficient use of electricity, and establish a telephone information service. Many suppliers offer information on their web sites related to electricity conservation. Information ranges from pointers on how to reduce consumption, to references to active government programs such as the Department of the Environment's Home Efficiency Scheme (EHES), which provides grants to qualified income-sensitive homeowners. Some suppliers, such as Scottish and Southern Energy PLC, Swalec, and Southern Electric, have links on their web sites to companies that sell high-efficiency equipment and products.

Promotion of energy efficient products through a labelling scheme has recently been initiated by UK legislation. The legislation will require that certain new domestic appliances display a label showing the appliance's efficiency rating.

1.3 Finland

DSM activities overseen by MOTIVA in Finland

Members of the business sector voluntarily commit to consumption reduction plans

Although Finnish legislation holds electricity companies responsible for promoting energy efficiency in their customer base, distributor involvement in the provision of DSM has been negligible in practice. The vast majority of DSM activities have been overseen by the Information Centre for Energy Efficiency (MOTIVA), established by the federal government in 1993 to distribute information, stimulate technological development, and promote the adoption of energy-efficient practices and equipment. Finland's strategy to encourage energy efficiency in the business sector has centred on voluntary agreements with industry associations. Companies from each industry who sign these agreements commit to a consumption reduction plan and an annual review of achieved results. As of 1999, firms representing approximately 80% of total Finnish industrial electricity use have joined, yielding annual savings of 1.3 TWh. In the commercial sector, the coverage of the voluntary agreements approached 68% by 2001. The success of these endeavours illustrates the combined influence of a sense of public obligation and governmental pressure in inspiring greater energy efficiency from the business community.

Government funding has helped to promote energy audits

More traditional forms of DSM are also abundant. Since 1992, the Ministry of Trade and Industry (MTI) has subsidized up to 40%-50% of the cost of comprehensive energy audits, producing an estimated Fmk 830 million in cumulative savings over the period 1992-99 from a total subsidy of Fmk 59 million. MTI also provides grants for efficiency upgrades by industrial customers (up to 30% of capital expenditures) and for home renovations (typically 20% of cost). In accordance with EU recommendations, MOTIVA has implemented an energy labelling system and minimum efficiency requirements for certain appliances, as well as a stricter building code intended to decrease the energy consumption of new buildings by 30%. In the past, MOTIVA has been involved extensively in funding R&D for conservation technologies, and sponsoring competitions (with monetary prizes) challenging manufacturers to produce the best-designed energy-efficient windows, refrigeration systems, and office lighting installations. Lately, these programs have been de-emphasized in favour of the voluntary agreements, audits, and information initiatives. However, the government recently issued a new energy-efficiency action plan and a national climate strategy that reinstate and expand Finland's DSM package while introducing a new orientation toward diminishing CO_2 emissions in light of the Kyoto Protocol.

1.4 Sweden

Centralized authority for DSM (STEM) in Sweden

In 1998, Sweden made a significant commitment to energy efficiency with the launching of several long-term government programs and the transfer of full responsibility for DSM initiatives to a new centralized authority called the Swedish National Energy Administration (STEM). Due to uncertainties over the restructuring process and concerns over the recovery of costs incurred by demand management activities, distribution companies had been virtually inactive with regard to DSM. This void was filled by STEM which allocated SKr 450 million between 1998 and 2002 to disseminate energy-efficiency information and administer high-efficiency equipment certification programs. STEM also directs a 7-year, SKr 9.2 billion program (commenced in 1998) to invest in R&D for new technologies that promote energy efficiency and to advance the market penetration of district heating, among other endeavours.

Voluntary approach in industrial sector

Information, education and training approach to smaller sectors

Demand management in the industrial sector is encouraged through voluntary agreements with large energy-intensive companies, similar to the practice in Finland. The companies develop energy-efficiency action plans in response to the recommendations of a usage analysis performed by STEM. The business community also benefits from incentive agreements with STEM for the adoption of high-efficiency technologies. The development of these technologies is supported in turn by programs that encourage competition among manufacturers to invent more energy-efficient products. With a 5-year budget of SKr 100 million, the technology procurement initiatives have resulted in the introduction of 15 new technologies in the residential and commercial sectors. The role of educating and training customers on opportunities for energy-efficiency improvements has been largely devolved to regional energy centres and local authorities, although STEM provides direction to these efforts. Finally, the advocacy of district heating represents an important component of Sweden's residential DSM initiative. STEM's financial support for conversions from electric to district heating in 1998-99 has yielded an estimated reduction in electricity use of 230 GWh. This contrasts with Finland, where district heating is more widespread (covering 48% of total space heating demand) but receives no direct assistance from government.

2 Funds Collection (New York, Vermont, Wisconsin)

Funds collection role

2.1 New York

Unlike the majority of jurisdictions reviewed in this paper, New York developed a separate entity called the New York State Energy Research and Development Authority (NYSERDA) to administer PSBC funds collected through the ratepayers. This agency has applied the PSBC proceeds to run over 30 energy efficiency programs, including the "Energy $mart" program designed to support certain public benefit programs during the transitional phase to a more competitive market. NYSERDA was created in 1975 for the purpose of promoting and selling energy-efficient products and services, funding R&D for new energy technologies, encouraging high efficiency standards for buildings under construction, performing energy audits, and educating consumers about high-efficiency alternatives available to them. The authority is comprised of 13 members, with a chairman appointed by the governor. NYSERDA reports directly to the governor who has power of approval over all NYSERDA decisions. Funding for NYSERDA comes from a combination of general tax revenues; PSBC funds transferred from distributors; and, voluntary annual contributions by the New York Power Authority, the Long Island Power Authority, and a limited amount of corporate funding. Under the current structure of New York's electricity market, the utilities provide only a minimal role in the funding for demand management programs.

Separate body (NYSERDA) administers funds and runs over 30 energy efficiency programs in New York

Promotes development and utilization of energy efficient products and services

Funding comes from a combination of sources, including funds collected by distributors

Programs funded by NYSERDA are referred to as Program Opportunity Notices (PONs). Currently, PONs include initiatives through which an organization promotes the use of energy efficient appliances such as ENERGY STAR products; initiatives involving energy and environmental research and development, which in turn are used by both the public and private sectors; and, initiatives directed toward specific areas such as the use of a certain type of fuel (such as ethanol, an end product of New York farm-grown corn), or alternative forms of electricity generation such as wind power.

Funding for demand management initiatives totalled $234 million between 1998 and 2000. $162 million of this was directed to energy efficiency programs. Roughly one quarter of the remainder was allocated to NYSERDA to develop statewide programs for demand reduction.

2.2 Vermont

In Vermont, state sponsored, non-profit entity "Efficiency Vermont" created to administer DSM on behalf of distributors

Funded by a systems benefit charge collected by distributors

An alternative form of funding demand management is represented by Efficiency Vermont, created in June, 1999, the nation's first Energy Efficiency Utility (EEU). Similar to NYSERDA, Efficiency Vermont is not involved in the distribution of electricity to customers, but rather serves as administrator of DSM programs on behalf of the state's distributors. Efficiency Vermont is a state-sponsored, non-profit entity that operates separately from the state's electric utilities and provides customers with financial incentives to adopt energy efficient measures. The EEU is overseen by a consortium selected by the Vermont Public Service Board, consisting of a fiscal agent, a contract administrator, and an advisory committee. It is funded by an energy efficiency charge (EEC), which is a non-bypassable, volumetric system benefits charge included in the bills of electric utility customers. Although statewide system benefits collected may not exceed $17.5 million per year, the charge amount may differ for each electric utility due to pre-EEU demand management program structure differences.

Similar to NYSERDA, Efficiency Vermont is involved in the promotion of ENERGY STAR products, programs that provide financial and technical assistance to commercial and industrial customers in installing energy efficient equipment, as well as low-income programs designed to lower the electricity bills of qualifying residential customers through energy saving measures such as free energy audits and installation of energy efficient products. Furthermore, Efficiency Vermont offers programs to farmers to help them reduce electrical costs through various energy efficient measures.

Similar to NYSERDA, broad spectrum of energy efficiency offers to all market sectors

2.3 Wisconsin

Following a successful 1998 pilot program to test a state-funded, utility-sponsored energy efficiency program, Wisconsin's legislature passed Act 9 (1999) requiring the Department of Administration (DOA) to create a statewide public-private partnership to oversee energy efficiency programs, called Wisconsin Focus on Energy (WFOE). Similar to New York and Vermont, WFOE will be funded through public benefit charges collected from energy consumers by the utilities, and administered by the DOA. The DOA is responsible for setting the level of these public benefit fees, with the consultation of the Council on Utility Public Benefits. The PSBC may not be volumetric (i.e., based on kWh consumption), but rather a percentage of the customer's total electricity bill.

In Wisconsin, statewide public-private partnership set up in 1999 and administered by government

Funded by systems benefit charge collected by distributors

In addition to energy efficiency projects, the WFOE will include demand reduction goals for consumer education, with the hope that such an initiative will reduce the need for more "interventionist" DSM. As in other jurisdictions reviewed, WFOE promotes the use of ENERGY STAR products and distributes information on techniques

Demand reduction goals for consumer education, plus comprehensive set of programs like those offered in other jurisdictions surveyed

for energy efficient improvements to multi-family residences. Also included in programs administered by WFOE are trade shows and training seminars designed to inform the consumer on various methods of energy conservation. The “Major Markets Segment” of WFOE is comprised of a team of independent subcontractors who provide non-residential electricity customers with educational/training services, financial support, and technical assistance. WFOE offers these energy efficiency auditing and consulting services free of charge to all eligible customers.

3 Facilitation and Education (Norway, Nova Scotia)

Facilitation and education role

3.1 Norway

Local utilities required by legislation to provide information in Norway

Norway passed an Energy Act in 1991 which distinguished the difference between power sale and production, and provided customers with a choice of retail suppliers. As part of the Act, local utilities were required to provide customers with information and advice on the efficient use of energy. With the release of a 1993 White Paper on Energy Efficient Policy, the Norwegian government redirected the nation's energy efficient programs towards information and education, and eliminated grant schemes for various sectors due to problems with "free-riders." Through this action, the government inferred that a critical "barrier to entry" for energy efficiency programs was lack of information and knowledge. As a result, distribution companies were assigned the role of facilitator and educator for energy efficiency programs. The distributor was no longer directly involved in the implementation of demand management, however it was expected to provide information on methodologies that might lead to the efficient use of energy.

Distributors collect funds for regional energy efficiency centers

Centers provide services to consumers

Government also funds and carries out information programs

Distributors offer peak load management programs

Similar to the PSBCs common in the US, Norwegian utilities collect a supplementary charge of up to NKr 0.003 per kWh (on average NKr = US$.13 in 1999) on transmission tariffs at the lowest grid level to fund DSM activities. Clear separation between monopoly distribution and retail supply was not required by the utilities. Therefore, concern grew over potential misuse of PSBCs for utility self-interest (e.g., marketing incentives or customer retention). Therefore, to mitigate these concerns, NVE (the regulatory agency) established a number of Regional Energy Efficiency Centres (REECs) funded by DSM wire charges and owned in part by the utilities and third-parties in each region. The REECs provide impartial energy efficiency advice, general information, historical electricity consumption data, and environmental emission assessments to a full range of customer groups throughout Norway. Most demand management programs funded by the Norwegian government are restricted to targeted information campaigns, training materials, and energy management advice for large buildings. In addition to REEC offerings, utilities employ business-based DSM measures such as real-time pricing and interruptible load agreements with large users to help customers avoid peak prices (which have proved particularly beneficial for Norway's energy intensive industries, including paper mills and aluminum smelters).

3.2 Nova Scotia

Utility provides information, advise and audit services in Nova Scotia

Nova Scotia Power Inc. (NSPI), the principal supplier of electricity in the province, is involved in DSM in ways similar to that of distributors in Norway. NSPI is not directly involved in carrying out energy efficiency programs, but it does provide educational information, consulting, and auditing services targeted at reducing electricity consumption for the home or business. One method used for conveying information to their customers is through NSPI's web site. The site outlines customer services and provides information on free home heating and energy conservation analysis; educational information on topics ranging from how to read a meter to energy efficient products; an energy calculator that determines the cost of operating a range of household items on a bimonthly basis; and, bill management and usage analysis, including the ability to access a customer's consumption history over the past 13 months.

Programs aim to increase customer knowledge

The DSM initiatives used by NSPI are aimed at increasing customer knowledge in the area of electricity consumption, with the expectation that a knowledgeable customer will be more conscious of energy-saving practices in his household or business. Furthermore, NSPI has set up an Energy Advisor hotline for the purpose of assisting in the management of energy use. Combined with the billing options available through the utility's web site (e.g., the usage analysis and energy calculator), this service provides for an effective campaign for the facilitation of DSM.

4 Integrated Resource Planning (Denmark, New South Wales, Oregon)

Integrated resource planning role

4.1 Denmark[29]

Goal of IRP in Denmark - achieve optimum resource allocation in society

Denmark places high importance on energy and environmental issues in general, employs strict energy efficiency policy, and has the strongest system for IRP and DSM in Europe. Denmark boasts an IRP obligation mechanism that, in Europe, is considered to have contributed the most towards the spread of DSM activities. The goal of IRP is viewed as achieving optimum resource allocation in society. Energy efficiency is promoted using all available means, as long as it results in better socioeconomic conditions than would exist through the energy consumption and production that it replaces.

Distributors prepare DSM plans

IRP funded through a surcharge to all customers

Denmark introduced IRP in the electricity sector for both production and distribution companies in 1994. Distribution companies are required to prepare biannual DSM plans weighing the different supply and demand side options from a societal perspective. The companies fund the IRP mechanism through a volumetric surcharge of 0.6 DKr/kWh. This is justified by ensuring that all types of customers are provided with energy-saving opportunities. The two regional associations of vertically integrated power companies (ELSAM and ELKRAFT) are also obliged to prepare 15-year IRPs specifying how they will achieve commitments on energy efficiency and environment policies. Plans are reported to, approved and financed by, the Danish Energy Agency (DEA).

Government issues DSM guidelines

Distribution companies must evaluate the potential for supply-side savings and demand-side efficiencies by exploring alternatives such as conservation, small combined heat and power (CHP) projects, and renewables. Since 1995, the plans have been developed cooperatively by all utilities according to Ministry of Environment guidelines. According to the recently adopted Electricity Act in 2000, passed in accordance with EU directives regarding energy market liberalization, long-term plans are still considered as a public service obligation. The Ministry continues to issue guidelines on the design of DSM programs, with an emphasis on implementation. Distribution companies are responsible for implementing their DSM plans, and supply companies are required to offer DSM services to customers to retain their franchise rights. According to the DEA, Danish energy companies are saving about 1 TWh (about 3% of total consumption) per annum through the DSM plans facilitated through IRP.

4.2 New South Wales

Distributors have legislated obligation regarding IRP in New South Wales and are guided by a Code of Practice

Avoided cost the driver

The New South Wales (NSW) Electricity Supply Act, 1995, requires that each licensed electricity distributor in the state assess DSM initiatives that would defer or avoid further investment in the distribution network. The Demand Management for Electricity Distributors Code of Practice (Code of Practice) also recommends that electricity distributors evaluate and plan network investments simultaneously with other options, such as DSM, embedded generation and storage (i.e. heating/cooling storage). Like in Denmark, avoided cost is the main driver behind development of DSM initiatives in NSW.

The NSW Ministry of Energy and Utilities recently convened a working group to evaluate the Code of Practice. The working group proposed in its final report that the utilities should clearly disclose the expected constraints on the system for several years ahead (i.e., 5-10 years); specify the system constraints such that network and non-network options are visible; and, publicly announce their evaluation procedure and the cost of their recommended option. As a result, the regulator (the Independent Pricing and Regulatory Tribunal, or IPART) would allow the utility to recover the cost of the non-network initiatives (including DSM) through regulated revenues, up to an amount determined by the IPART based on an examination of avoided network costs.

Cost-benefit information

Table 3: Expenditure by NSW distribution businesses on DSM programs

Year	Cost of programs ($'000)	Opex saved (NPV$'000)	Capex deferred (NPV$'000)
1998-99	3319	10690	32581
1999-00	4977	14387	48131

Source: NSW Electricity Network Management Reports 1998-99 and 1999-00; all figures in Australian dollar terms.

Table 3, above, is an aggregate summary of information provided by the six electricity distributors in NSW as to the level of their DSM expenditures and the expected savings in operating expenses and deferred capital costs estimated as a result of the DSM initiatives. The estimated savings in operating expenses are more than 2½ times the program costs, and deferred capital expenditures are more than 9 times the program costs for both years. This suggests that the proposed DSM programs are worthwhile investments with an internal rate of return (IRR) in excess of 100% for both years, even solely on the basis of the anticipated operating expense savings.

DSM programs focus on load management

The DSM programs being offered by NSW distributors include load balancing, peak clipping, limited back-up, and base load reduction via fuel substitution. However, load-shifting programs have recently come under IPART scrutiny as they do not reduce "overall" demand, and therefore may cause adverse environmental effects. For example, in the July, 2001 Issues Paper entitled “Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services”, IPART notes that “off-peak water heating and ice storage for air conditioning encourage increased energy consumption and so can lead to increased greenhouse gas emissions.”

4.3 Oregon

Oregon employs IRP in both electricity and gas sectors

By the end of the 1970s, utility planners and policy makers in the US began to identify new approaches to meet energy requirements while simultaneously addressing environmental concerns. First, they looked at cost issues involved with supply and demand planning. A new approach became known as least cost planning or least cost utility planning (LCUP). As the process evolved to include more societal goals and strategic planning, it became known as IRP. By the end of the 1980s, over 30 state Public Utility Commissions (PUCs) in the US had adopted IRP. The 1992 Energy Policy Act (EPAct) required all electric utilities to employ IRP and to submit plans to their state PUCs. Shortly after EPAct was passed; however, many state governments began to consider "deregulating" or "restructuring" their gas and electric power industries. Though this has sparked discussion as to whether IRP should continue, or whether it is a burden that should be lifted from the utilities' shoulders, several deregulated states continue to employ IRP. For example, Oregon uses IRP (referred to as "least cost planning") in its regulatory practices for both its electricity and natural gas utilities.

In 1989, the Oregon PUC issued an order (Order No. 89-507) adopting least cost planning for all energy utilities in Oregon. At a minimum, the least cost planning process must involve the Commission and public prior to making resource decisions. Energy conservation measures are deemed to be cost-effective if the installed cost is less than the identified avoided cost per unit of energy for the expected life of the measure. Every two years, Oregon's gas and electric distributors must submit a DSM action plan in conjunction with an IRP. While the proposed DSM measures must be in accordance with an Oregon statute, which obligates all utilities to administer residential energy conservation programs and to provide financing for cost-effective projects, each utility has considerable discretion as to the form of DSM it implements. Utilities must periodically file estimates of avoided costs attributable to DSM to help the regulator evaluate the cost-efficacy of the initiatives underway.

PUC issued order adopting IRP for all energy utilities in 1989

Distributors file DSM plans in conjunction with IRP plans

Summarized below is an example of a utility 2-year IRP.

Table 4: Overview of Portland General Electric's (PGE)1998-99 IRP

Example of a 2-year IRP

	1998		1999	
	energy savings (MWa)	**program costs (millions of $)**	**energy savings (MWa)**	**program costs (millions of $)**
Budget	5.91	$12,000,000	6.18	$12,300,000
Actual	4.5	$7,200,000	6.18	$12,000,000

In 1998, PGE attributed the lower-than-expected results to unfavourable industry and economy-wide events. In 1999, PGE reported attainment of the 6.18 MWa target.

PUC mandated a systems benefits charge upon implementation of statewide restructuring

The Oregon PUC adopted rules for implementing state-wide electric industry restructuring law, Senate Bill (SB) 1149, in 2000. This required that electric companies file a "Resource Plan," proposing disposition of their existing generating resources that facilitates a fully competitive market; provides consumers with fair, non-discriminatory access to competitive markets; and, retains the benefit of low-cost resources for consumers. SB 1149 also mandated the implementation of a system benefits charge (SBC) to fund DSM and energy efficiency initiatives. The PUC ruled that even with industry restructuring the IRP obligation would remain effective for all distributors.

5 Target-oriented Implementation (BC, California, Minnesota, New Jersey)

Distributors and target-oriented DSM

5.1 In a Performance-based Regulatory Context

DSM in a PBR plan

5.1.1 British Columbia

In British Columbia penalty-reward frameworks different for each distributor

While British Columbia's two principal electricity distributors and primary gas distributor have been subject to some form of PBR, the provincial regulator has applied different approaches to incorporate DSM into the regulatory framework for each.

BC Gas

The BC Gas PBR plan expired in 2001, and the company is expected to apply for re-setting of a next generation plan. In the meantime, the company continues with its DSM obligations as follows. To encourage gas DSM activities, the British Columbia Utilities Commission (BCUC) introduced an achievement target for BC Gas in 1998 that would adjust the company's before-tax earnings based on its effectiveness in producing demand management results. If actual energy savings were to fall between 75% and 100% of the forecasted target, BC Gas would receive 3% of the total resource cost (TRC) net benefits; if savings exceeded 100% of the target, the reward would be 5%. These earnings modifications were introduced into the, then approved, PBR formula via a revenue stabilization adjustment mechanism, a deferral account that would stabilize sales revenues by capturing variances between forecasted and actual use per customer throughout the year. BC Gas would be able to freely allocate its allotted DSM budget across programs and would assume full responsibility for design and implementation. However, the efficacy of each initiative would be reviewed with the BCUC semi-annually.

West Kootenay Power

By contrast, DSM results by West Kootenay Power (WKP)[30] are rewarded through shareholder incentives designed to encourage the company to maximize its resource savings per dollar spent on demand management. On an annual basis, the BCUC forecasts the net benefits (calculated as avoided energy plus capacity cost savings less investment costs) anticipated to accrue to each customer class from WKP's approved DSM activities. Should actual attained benefits exceed 100% of these targets, shareholders are paid a progressively increasing share of net benefits; if WKP falls short of expectation, shareholders may be penalized for a fraction of the "lost benefits." Unlike other DSM reward frameworks (including that of BC Gas) based solely on reduced consumption, the WKP framework based on net benefits allows WKP to earn rewards by shifting usage to lower-cost hours or finding ways to deliver DSM more cost-effectively. The performance bands and penalties/rewards approved for 2000 are displayed in the table, below.

Table 5: Year 2000 Penalty/reward scheme for DSM performance at West Kootenay Power

Achieved net DSM benefits as % of planned benefits	Residential	General Service	Industrial
<50%	-6.0%	-4.0%	-3.0%
50-69%	-4.5%	-3.0%	-2.0%
70-89%	-3.0%	-2.0%	-1.0%
90-94%	0.0%	-1.0%	-0.5%
95-100%	0.0%	0.0%	0.0%
101-110%	3.0%	2.0%	1.0%
111-120%	4.5%	3.0%	2.0%
>120%	6.0%	4.0%	3.0%

While the potential for penalties suggests a harsher regulation of WKP than BC Gas, the BCUC stipulated that WKP would not be penalized in the aggregate. Customer class-specific penalties are only levied in the event of counter-balancing rewards from other customer classes, meaning that WKP shareholders are protected from DSM-related losses even if customer classes appear to be poorly served from a DSM perspective. As an additional incentive, WKP is allowed to amortize its DSM costs over an 8-year period and earn a return on unamortized balances.

5.1.2 California

CPUC sets budgets, targets, and reward structures by sector; distributors work to meet the targets

Source of funding is a systems benefit charge to all customers

The California Public Utilities Commission (CPUC) has been incorporating DSM incentives into its PBR regime for a number of years. Demand management expenditures by utilities declined over the mid-1990s, partly due to the increased role of the California Energy Commission (CEC) to promote conservation and peak-shaving. Nevertheless, in 1999 the four investor-owned utilities generated annual savings of 825 TWh, 156 MW of peak demand, and 14 million therms from budgets of $200 million for electricity and $43 million for gas. Shareholder incentives, that pay monetary rewards proportionate to the quantity of GWh saved through DSM, likely contributed to achievement of these results. Achievement of a minimum-acceptable level of load reduction results in a payment of 50% of the potential shareholder bonus, with successive 1% increments in performance above this minimum gradually increasing the payout up to a maximum amount (7% of the total DSM budget). Note that unlike British Columbia, there are no symmetric penalties for performance below the minimum in California, and success is judged by quantity reductions without regard to cost savings. The target reduction levels are based on analyses of the historical effectiveness of distributor investment in various types of energy efficiency programs, and are shown in the table below.

Table 6: Year 2001 Targeted DSM savings by California Utilities

	Minimum Threshold (50% earnings)			Maximum Threshold (100% earnings)		
Utility/Class	**TWh**	**MW**	**Therms (m)**	**TWh**	**MW**	**Therms (m)**
PG&E						
Residential	116.2	44.2	3.1	145.2	55.3	3.9
Non-residential	295.9	48.3	3.9	369.9	60.3	4.9
New construction	35.2	8.9	0.2	44.0	11.2	0.3
Total	**447.3**	**101.4**	**7.2**	**559.1**	**126.8**	**9.1**
SDG&E						
Residential	17.8	6.8	0.7	22.3	8.5	0.8
Non-residential	44.8	7.3	0.3	56.0	9.1	0.3
New construction	18.4	4.7	0.1	23.0	5.8	0.2
Total	**81.0**	**18.8**	**1.1**	**101.3**	**23.4**	**1.3**
SCE						
Residential	83.4	31.7		104.3	39.7	
Non-residential	185.3	30.2		231.7	37.8	
New construction	42.1	10.7		52.6	13.4	
Total	**310.8**	**72.6**	**0.0**	**388.6**	**90.9**	**0.0**
SoCalGas						
Residential	4.6	2.4	1.8	5.7	3.1	2.2
Non-residential	2.3	0.5	4.3	2.9	0.7	5.3
New construction	10.4	3.7	0.3	13.0	4.6	0.4
Total	**17.3**	**6.6**	**6.4**	**21.6**	**8.4**	**7.9**
Grand Total	**856.4**	**199.4**	**14.7**	**1070.6**	**249.5**	**18.3**

CPUC may provide direction on program design or targeting

DSM activities include information, rebate, and equipment programs

Because three of the four utilities distribute both electricity and gas, the CPUC establishes distinct budgets, targets, and reward structures for each sector; however, initiatives such as consumer education and funding for energy-efficient retrofits may embrace both sectors. While distributors develop their own programs and allocate their budgets across residential, non-residential, and new construction markets, the CPUC has cautioned distributors that any shifting of funds should be consistent with the principles of equity and targeting under-served markets. In 2000, the CPUC also directed them to expand their weatherization, HVAC installation, and new construction initiatives in compliance with updated provisions in California's Energy Efficiency Standards for Residential and Nonresidential Buildings (AB 970). Due to the recent crisis in the electricity market, most current utility initiatives have emphasized load-shifting and short-term conservation measures rather than longer-term market transformation. Distributors have concentrated on customer-focussed education, rebates, and equipment retrofit programs, while the CEC has concentrated on market transformation efforts such as stricter building standards and the development of energy-efficient technologies. The majority of funds for distributor DSM activity are provided through a public goods charge (PGC), a volumetric (i.e., per-kWh) surcharge collected from ratepayers. Funds are also available from previously unspent funds and balancing account interest.

5.2 In a Traditional Regulatory Context

Distributor role in traditional cost of service context

5.2.1 Minnesota

Distributors required to prepare plans in Minnesota

Funded by surcharge to distribution customers based on total percentage of gross revenues

Conservation plans based on legislated objectives and targets stem from statewide goals

Distributors in Minnesota are charged with administering their own DSM initiatives, although their freedom is circumscribed by a combination of legislated restrictions and intense regulatory oversight. Under the provisions of the 1991 Omnibus Energy Act, all utilities must submit a Conservation Improvement Plan (CIP) every two years, presenting their proposals for DSM expenditures and projects to the regulator for approval. Gas distributors are mandated to spend 0.5% of gross revenues on CIP programs while electricity distributors must earmark 1.5% of revenues toward their CIPs. Moreover, the regulator is entitled to accept or reject CIPs based on whether they satisfy the four conditions outlined in Minnesota's Energy Conservation Statute: 1) they promote cost-effective utility investment in conservation, 2) they deliver the majority of benefits to ratepayers, 3) they link incentive payments to DSM cost efficiency, and 4) they contribute to ensuring "just and reasonable" rates. According to the standardized DSM methodology adopted in 2000, each distributor's energy savings objective is a function of the statewide goal for usage reduction, adjusted for the ratio of the individual company's statutory minimum CIP expenditure level to its approved budget. Note that this design encourages both energy reduction and cost minimization in DSM delivery.

PUC reviews DSM program results, not just cost consequences

DSM programs include equipment rebates, funding for retrofits, and audit services

As a reward for achieving or exceeding their targets, distributors receive a fraction of the "net benefits" (principally avoided costs) generated by their conservation initiatives in the following year, in addition to full recovery of program costs through their rate base. This reward actually triggers once the company achieves just 90% of its savings target, then increases with every percentage point of improvement up to a generous maximum of 30% of total approved CIP expenditures. These incentives are made available partly as a substitute for allowing recovery of lost margins, which is often a feature of more traditional DSM regulation. Prior to the CIP deadline, the PUC reviews the success and failure of each distributor's DSM projects and recommends modifications to be instituted in the new CIP (underscoring the close regulatory scrutiny found in Minnesota when compared to other jurisdictions surveyed in this paper). The reviews for gas and electricity projects are conducted in staggered years, suggesting that the regulator regards them independently. Nevertheless, most DSM programs undertaken by the state's combined utilities have encompassed both gas and electricity, with the emphasis on appliance rebates, funding for energy-efficient retrofits, and auditing services.

5.2.2 New Jersey

Detailed distributor DSM requirements specified in an administrative code in New Jersey

BPU evaluates and approves DSM plans

The legal framework for DSM in New Jersey is similar to Minnesota's in many respects, with both legislative and regulatory constraints on the composition and scope of each distributor's DSM undertakings. Title 14 of New Jersey's Administrative Code specifies the required elements of utility DSM plans, outlines the incentive mechanism, defines the cost-benefit test to which each program is subjected, provides for the recovery of program costs along with lost margins from conservation-induced reductions in sales, and describes the review and approval process managed by the Board of Public Utilities (BPU). On the regulatory side, the BPU holds a periodic comprehensive resource analysis (CRA) proceeding which evaluates the DSM plans submitted by utilities and approves appropriate funding levels. Utilities can design their own programs and allocate their funds accordingly provided that each initiative meets the BPU's cost-benefit criterion. Even after surmounting the approval process, distributors must issue quarterly reports to the regulator to demonstrate their progress.

Systems benefit charge collected by distributors to fund DSM activities

Performance incentives scaled back recently

DSM plans include information- and incentive-based programs to promote energy efficient products and services

Unlike in still-regulated Minnesota, where DSM budgets are incorporated directly into the rate base, New Jersey distributors collect a societal benefits charge (SBC), half of whose proceeds are allocated 75% to energy efficiency and 25% to renewables programs, and channelled into specific DSM activities through the CRA proceeding. Shareholder incentives for good performance can be earned through two means: 1) a shared savings mechanism through which distributors can receive a negotiated share of net benefits, and 2) a standard pricing offer by which the distributor pays a set price (corresponding closely with avoided cost) to customers and ESCOS for verifiable demand savings. This latter method drastically reduces the distributor's administrative costs for DSM, although the scope for profitability is limited to utilities able to procure savings through their conservation-oriented subsidiaries. It should be noted that the most recent proceeding scaled back the availability of performance incentives, and announced that a consultant will assess the possibility of transferring DSM control to a centralized agency. As in Minnesota, utilities that distribute both electricity and gas (in New Jersey, only PSE&G fits this description) receive separate budgets for the two businesses, as illustrated in the table, below, by the approved funding levels for energy efficiency and renewables initiatives for 2001-03. Most current DSM programs revolve around appliance rebates, the promotion of ENERGY STAR homes, financial incentives for using high-efficiency products in building construction, and walk-through energy audits.

Table 7: Approved DSM budgets for New Jersey distributors

Distributor	**millions $**		
	2001	**2002**	**2003**
Conectiv	$8.1	$9.8	$11.4
Elizabethtown	$4.0	$4.0	$4.2
GPU	$32.3	$32.8	$34.9
New Jersey Natural Gas	$4.0	$4.0	$4.2
PSE&G electric	$43.0	$43.3	$43.4
PSE&G gas	$20.8	$22.0	$21.9
Rockland Electric	$0.5	$0.5	$0.5
South Jersey Gas	$2.2	$2.8	$3.5
Total	$114.9	$119.2	$124.0

6 Participation in Demand Bidding Programs (Australia, New York, California)

Demand bidding

6.1 Australia

Demand side bidding in Australia's electricity market provided for, but barriers remain

Despite being specified in the Code of Practice, there has been virtually no demand side bidding in the National Electricity Market (NEM). In March 2000, NECA (the National Electricity Code Administrator) undertook a survey on demand-side participation in the NEM and found that a key disincentive to the use of direct demand-side bidding, as perceived by end-users (the final customers), was the requirement for absolute symmetry between the rules governing the supply and demand sides of the market. Given that the market rules were designed primarily for the supply side of the market, particularly generators, these rules have imposed high transaction costs on demand side bidders. This has been a concern, given the interest in active participation by major end-use customers.

In September 2000, NECA proposed Code changes to make the arrangements for demand-side bidding more attractive to end-use customers. These changes sought to address the perceived barriers to demand-side bidding by:

- restructuring and simplifying the arrangements in order to improve the attractiveness of registering as a scheduled load;
- increasing flexibility for load seeking to switch between scheduled and market (non-scheduled) loads;
- addressing the sanctions on market customers for non-conformance by scheduled loads; and

- managing non-conformance by scheduled loads, with NEMMCO applying constraints or a default dispatch bid on the participant's behalf.

The success of these initiatives has not yet been measured, since prices have generally been fairly low in the market over the last twelve months (with the exception of several price spikes in the South Australia and Victoria regions) due to overall capacity surplus conditions.

6.2 New York

New York ISO seeking to expand its demand-side programs

A pressing question facing the state of New York is the inadequacy of the current pace of generating capacity additions to sustain projected demand growth. This is exacerbated by the transmission constraints that prevent new plants in upstate New York (where capacity reserve margins are high) from relieving the supply-demand imbalances in New York City and Long Island areas. Although a number of plants have been proposed, and the New York Power Authority recently managed to fast-track the commissioning of several peakers by utilizing an expedited permitting process for smaller units, the Article X approval procedures have not accelerated the process as much as it was originally hoped.

Consequently, the ISO plans to expand its demand-side programs to relieve some of the pressure on the existing generation portfolio. In early 2001 the ISO implemented its innovative day-ahead demand response (DADR) scheme, in which load serving entities (LSEs) submit bids indicating their willingness to reduce demand at a certain price level, which are then "dispatched out" on a merit-order basis.

Under this program, load reduction bids are allowed to set the locational-based marginal price (LBMP). A customer whose load reduction bid is accepted would normally be paid the greater of its bid amount or the LBMP. However, until October 2003, those bidders that do not own or control a local generator, and are willing to curtail consumption, will receive an additional incentive credit corresponding to the degree by which their demand reductions lowered the market-clearing LBMP.

Additionally, a supplemental emergency demand response program (EDRP) allows participants to pledge load reductions to be triggered under dire system conditions, in exchange for payments equalling the higher of $500/MWH or the real-time zonal LBMP. To date, 13 LSEs, 9 load aggregators and 7 end-users have either registered or are in the process of registering for the EDRP. The total capacity that could be curtailed under this program is about 700 MW. The New York ISO intends to devise a third demand-reduction plan that would permit loads to specify a price above which they no longer wish to buy energy from the day-ahead market.

6.3 California

A statewide demand bidding program has been set up in California to encourage voluntary load reduction

In response to the energy shortages of the past year, a statewide demand bidding program (DBP) has been established in California through Executive Order D-39-01. All existing participants in the Discretionary Load Control Program (DLCP, administered by the California ISO) and the utilities' Voluntary Demand Reduction Programs (VDRP) were rolled into this statewide demand bidding program. Due to concerns about the creditworthiness of utilities, this program has been funded by the California Department of Water Resources (CDWR). Total load participation in this program has been about 1,000 MW through the summer of 2001. The DBP is a voluntary electric-load reduction program. It offers participating businesses the opportunity to commit to reducing their load on a day-ahead basis, and to receive financial incentives for this load reduction. The program allows the CDWR to reward local businesses for reducing demand rather than paying out-of-state suppliers a higher price for additional electricity. All three major utilities in the state (Southern California Edison, San Diego Gas and Electric, and Pacific Gas and Electric) participate in this program.

Participation limited to customers who are not exposed to real time pricing and are able to commit a minimum reduction of 100 kW

For end users to participate in the DBP, they must have the ability to reduce electric load by at least 10 %, with a minimum reduction of 100 kilowatts (kW), and should not be already exposed to real time pricing. Participants are required to sign a contract and agree to participate in the program for 12 months. They receive a credit applied to their monthly electricity bill for verified electric load reductions implemented following the acceptance of their bid. In addition, some utilities provide participants with upgraded metering equipment and a communication link between the meter and an internet service at no cost to help them monitor their usage. Opportunities to receive credits are expected to occur between July 30, 2001 and October 31, 2002, during weekdays. Every day, customers may log onto their utility's web site to place a curtailment bid for the next day by 1:00 p.m., and to check after 5:00 p.m. to see if their bid was accepted or rejected by the CDWR. Customers will be given the opportunity to submit bid commitments in four-hour blocks: 8:00 a.m. to 12:00 p.m., 12:00 p.m. to 4:00 p.m., and 4:00 p.m. to 8:00 p.m. The customer must bid the same price and load commitment (in kW) for each of the four hours within a block of time.

D References

1. Howard Wetston, Q.C., Chair, Ontario Energy Board. Letter to the Honourable John Baird, Minister of Energy. August 8, 2003.

2. Navigant Consulting. *Blueprint for Demand Response in Ontario.* April 2003. (pp. 26 and 35).

3. Navigant Consulting. *Blueprint for Demand Response in Ontario*. April, 2003.

4. Electricity Distributors Association. *Distributors' Recommendations on the Policy Framework for Demand-Side Management (DSM): EDA Policy Position on DSM Activities*. July 2003.

5. Activities conducted on the utility's side of the customer meter. Activities designed to supply electric power to customers, rather than meeting load though EE measures or on-site generation on the customer side of the meter; i.e., generation, transformation, and transportation.

6. Activities conducted on the customer's side of the customer meter. Load management techniques a utility can use to reduce or alter its load profile, such as EE improvements and load shifting; i.e., interval metering, water heater control pilot/relay wires and timer systems, and time-of-use rates.

7. Ontario Energy Board. E.B.O. 169 Report of the Board in the matter of the *Ontario Energy Board Act, R.S.O. 1990*, c.O.13; and in the matter of section 13(5) of the said Act; and in the matter of a hearing to inquire into, hear and determine certain matters relating to Integrated Resource Planning on the distribution systems of The Consumers' Gas Company Ltd., Union Gas Limited and Centra Gas Ontario Inc. July 23, 1993

8. Navigant Consulting. *Blueprint for Demand Response in Ontario.* April 2003.

9. Flat rate water heating provides unmetered energy to heat water. The amount of consumption is estimated, based on the wattage of the heating elements and the size of the tank. For example, for a 40 gallon, 1000/3000 watt installation, the estimated monthly consumption is about 370 kWh.

10. Independent Electricity Market Operator. Announcement and Supporting Material for Consultation on the Evolution of the Market. *Setting Priorities for the Evolution of the Market Design*. December 20, 2001.

11. TCE, a small retailer in Texas that recently became bankrupt, followed this model. Australian Energy Services, an aggregator in Australia, modelled itself on a telecommunications reseller and in so doing aggregates load. But again, it does not participate in demand-side bidding.

12. The CRA study in Australia, “Electricity Demand-side Management Study” for VENCorp (September 2001), summarizes the problem. It notes, for example, that all the demand responsiveness in Victoria is derived from just 15 customers.

13. California ISO. Participating Load Program Process. February 22, 2001. (http://www.caiso.com/docs/2001/02/22/200102221609473436.doc)

14. The regulator took the position that the investor owned utility retail arms should not be allowed to aggregate, and interruptible load should not participate in PLP.

15. The National Association of Regulatory Utility Commissioners. *Policy and Technical Issues Associated with ISO Demand Response Programs*. July 2002.

16. The Kyoto agreement commits Canada, and in turn Ontario, to a set level of emissions.

17. Bill 210, *Electricity Pricing, Conservation and Supply Act, 2002*. See: <http://www.ontla.on.ca/library/bills/210373.htm >

18. Independent Electricity Market Operator. *Leading the Way - Evolving Ontario’s Electricity Market*. 2002 Annual Report.

19. Superceded by the Code of Conduct for Gas Marketers (March, 1999) and the Affiliate Relationships Code for Gas Utilities (July, 1999).

20. Ontario Energy Board. H.R. 19. Ontario Hydro H.R. 19 Interim Report. August 28, 1990.

21. Ontario Energy Board. H.R. 20. Report of the Board in the Matter of a Reference From the Minister of Energy Respecting Ontario Hydro's Proposed Electricity Rates For 1992. August 26, 1991.

22. Ibid.

23. Ontario Energy Board. RP-1999-0034 Decision with Reasons in the matter of a proceeding under sections 19(4), 57, 70, and 78 of the *Ontario Energy Board Act, 1998* S.O. 1998, c. 15, Sched. B to determine certain matters relating to the Proposed Electric Distribution Rate Handbook for licensed electricity distributors. January 28, 2000. Paragraph 6.0.7.

24. Ontario Energy Board. RP-1999-0017 Decision with Reasons in the matter of the *Ontario Energy Board Act, 1998*, and in the matter of an Application by Union Gas Limited for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas in accordance with a performance based rate mechanism commencing January 1, 2000; and, in the matter of an Application by Union Gas Limited for an order approving the unbundling of certain rates charged for the sale, distribution, transmission and storage of gas. Section 2.9.6.

25. The companies' DSM evaluation reports contain specific details on DSM program activity: (1) Enbridge Gas Distribution Demand Side Management F2001 Monitoring and Evaluation Report. November 18, 2002. (2) DSM 2001 Evaluation Report. Union Gas. June, 2002.

26. Ontario Energy Board. RP-2002-0133 Partial Decision with Reasons in the matter of the *Ontario Energy Board Act, 1998*, S.O. 1998, C.15, Sch. B; and, in the matter of an Application by Enbridge Gas Distribution Inc. for an order or orders approving or fixing rates for the sale, distribution, transmission and storage of gas for its 2003 fiscal year. Paragraph 336.

27. Bill 210, *Electricity Pricing, Conservation and Supply Act, 2002*. See: <http://www.ontla.on.ca/library/bills/210373.htm >

28. Note: all customer and consumption data are drawn from most recent available year (1999 or 2000).

29. Energy consumption in Denmark is on the decline: Total energy consumption in Denmark is falling: in 2000, consumption fell by 0.7%, even while the Danish economy has grown by 3.2% during the same period. This suggests that Denmark is increasing its efficiency of energy usage.

    The energy policy initiatives implemented in recent years to increase efficiency in energy consumption and reduce Danish CO2 emissions had visible statistical effects. Together with the falling energy consumption, the increase in renewable energy led to a 2.1% fall in CO2 emissions in 2000. Relative to 1988, gross energy consumption has increased by just over 2%, CO2 emissions have fallen by 11% and GDP has grown by 27%.

    Source: Danish Environment & Energy Newsletter, No 11 - November 2001

30. Now Aquila Networks Canada.

E Glossary

Term	Meaning	Source
Alternative Energy Sources	Non-traditional energy sources, including renewable sources (defined below), and non-renewable sources, including fuel cells, waste, or landfill gas.	*working definition for the purposes of this paper*
Conservation Programs	Programs aimed at increasing the efficiency of energy use, thereby reducing consumption.	E.B.O. 169-III Report of the Board, July 23, 1993
Demand Side Bidding	Demand side bidding (DSB) is a mechanism that enables consumers to actively participate in electricity trading, by offering to undertake changes to their normal pattern of consumption. Load-serving entities contract with customers willing to curtail their consumption if energy prices exceed a certain level, then submit these bids into the market. Unlike traditional DSM programs designed to achieve lasting reductions in energy usage, demand bidding programs are geared toward temporary decreases in load under peak system conditions.	*working definition for the purposes of this paper*
Demand Side Response	Actions voluntarily taken by a consumer to adjust the amount or timing of his energy consumption. Actions are generally in response to an economic signal (e.g., energy price, or government and/or utility incentive), and may include voluntary load dispatch/shift, distributed generation, HVAC, and thermal/ice storage.	*working definition for the purposes of this paper*
Demand	The rate at which electricity or natural gas is delivered to or by a system in a given instant, or averaged over a designated period, usually expressed in Mcfs (natural gas) or kW (electricity).	*The Power Reference* by Ontario Power Generation

Term	Meaning	Source
Demand Side Management (DSM)	Actions taken by an energy utility, retailer, or services company which are designed to influence the amount or timing of a consumer's energy consumption. Actions may be designed to increase energy efficiency, encourage energy conservation or implement load management.	*working definition for the purposes of this paper*
Demand-Side Options	Load management techniques a utility can use to reduce or alter its load profile, such as energy efficiency improvements and load shifting.	E.B.O. 169-III Report of the Board, July 23, 1993
DSM Activity/Measure	An action taken by customers to alter the amount or timing of their energy consumption.	E.B.O. 169-III Report of the Board, July 23, 1993
DSM Program	An organized collection of related DSM activities or measures which a utility may use to affect the amount and timing of a customer's energy consumption.	E.B.O. 169-III Report of the Board, July 23, 1993
DSM Portfolio	A group of DSM programs which have been selected and combined in order to achieve the objectives of a utility's DSM plan.	E.B.O. 169-III Report of the Board, July 23, 1993
DSM Strategy	The combination of a portfolio of DSM programs and its implementation plan which a utility intends to employ in order to achieve its DSM objectives.	E.B.O. 169-III Report of the Board, July 23, 1993
DSM Plan	A strategic plan which sets objectives for, and directs and controls the implementation, monitoring and improvement of a utility's preferred DSM portfolio.	E.B.O. 169-III Report of the Board, July 23, 1993

Term	Meaning	Source
Energy Service Company (ESCO)	An organization that contracts with energy users, landlords and/or utilities to evaluate, design, install and monitor capital and operating improvements in an existing building facility or industrial process, to reduce energy and operating costs over a contract period. ESCOS typically finance the costs of these improvements and receive payment by sharing in the resultant energy and operating savings.	E.B.O. 169-III Report of the Board, July 23, 1993
Energy Consumption	The quantity of energy used, typically expressed as M^3 (natural gas) or kWh (electricity).	*The Power Reference* by Ontario Power Generation
Energy Conservation	Any action that results in less energy being used than would otherwise be the case. These actions may involve improved efficiency, reduced waste, or lower consumption, and may be implemented through new or modified equipment or behaviour changes.	*working definition for the purposes of this paper*
Energy Efficiency	Using less energy to perform the same function. This may be achieved by substituting higher-efficiency products, services, and/or practices. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems. Energy efficiency can be distinguished from demand side management in that it is a broad term that is not limited to any particular sponsor (e.g., a utility, a retailer, an energy services company).	*working definition for the purposes of this paper*

Term	**Meaning**	**Source**
Energy Services	1. (End-User) The comfort, lifestyle or industrial production capability an end-user obtains through the use of an energy form. 2. (Utility) The storage, transmission and distribution of natural gas and any other services provided by the utility as part of the delivery of natural gas to its customers.	E.B.O. 169-III Report of the Board, July 23, 1993
Gas Marketer	means a person who is licensed under Part IV of the *Ontario Energy Board Act, 1998* and: (a) sells or offers to sell gas to a low-volume consumer; (b) acts as the agent or broker for a seller of gas to a low-volume consumer; or (c) acts or offers to act as the agent or broker of a low-volume consumer in the purchase of gas	Code of Conduct For Gas Marketers (Ontario Energy Board)
Gas Vendor	means a person who sells or offers to sell gas to a consumer, acts as the agent or broker for a seller of gas to a consumer, or acts or offers to act as the agent or broker of a consumer in the purchase of gas	Gas Distribution Access Rule (Ontario Energy Board)
Integrated Resource Planning (IRP)	A planning method for use by natural gas and electric utilities whereby expected demand for energy services is met by the least costly mix of demand-side and supply-side programs and strategies. Sometimes referred to as Least-Cost Planning.	E.B.O. 169-III Report of the Board, July 23, 1993
Load Management	Activities or equipment to induce consumers to use energy at different times of day or to interrupt energy use for certain equipment temporarily in order to meet the objectives of peak shaving and/or load shifting from peak to off-peak. Examples include interruptible rates, time-of-use rates, load control devices, and air conditioner cycling programs.	*working definition for the purposes of this paper*

Term	Meaning	Source
Load Profile	The demand for a utility's energy supply or the amount of consumption by a particular customer or group of customers displayed over time to illustrate consumption patterns during a specified period.	E.B.O. 169-III Report of the Board, July 23, 1993
PBR	Performance-based regulation	n/a
Societal Cost Test	An evaluation of the costs and/or benefits accruing to society as a whole, due to an activity.	E.B.O. 169-III Report of the Board, July 23, 1993
Supply-Side Options	Expansion or replacement projects, such as pipeline or storage construction, upstream of the customer's meter.	E.B.O. 169-III Report of the Board, July 23, 1993
Time-of-Use (TOU) Rates	The application of lower rates during night time, weekends, holidays and summer; the application of higher rates during day-time, work days and winter.	Ontario Hydro H.R. 19 Interim Report, August 28, 1990
Total Resource Cost Test	An evaluation which incorporates all of the costs and benefits included in the Societal Cost Test with the exception of externalities.	E.B.O. 169-III Report of the Board, July 23, 1993
Utility Test	An evaluation of the impact of a DSM program on a utility's revenue requirement as a result of a change in costs. Excludes any lost revenues due to the DSM program.	E.B.O. 169-III Report of the Board, July 23, 1993