Ontario

Ontario Energy Board

Smart Meter Implementation Plan

Report of the Board To the Minister

January 26, 2005

Smart Meter Implementation Summary

On July 16, 2004, the Minister of Energy asked the Ontario Energy Board to develop an implementation plan to achieve the Government of Ontario's smart meter targets for electricity: 800,000 smart meters installed by December 31, 2007 and installation of smart meters for all Ontario customers by December 31, 2010. Smart meters will provide customers with consumption information that will allow them to manage their demand for electricity. This is expected to result in more efficient use of Ontario's existing supply of electricity and reduce reliance on external sources.

The Minister asked the Board to identify and review options for achieving the targets and to address several specific issues. In developing this implementation plan, the Board has consulted with stakeholders through four processes. In July, the Board issued a discussion paper and invited comment. In late August, the Board struck four working groups of interested and experienced stakeholders to study the options and to identify detailed implementation issues. In November, the Board received submissions on a draft implementation plan released for public comment. Based on those submissions, the Board asked for further submissions in January on a narrow area of investigation. The Board has benefited greatly from all of this input and has considered it carefully in developing the implementation plan.

The smart meter initiative is both challenging and complex, but nonetheless feasible. The timelines are aggressive and will require a high level of cooperation between key players over several years. Resources may be limited due to competing electricity initiatives, particularly in the first phase until the end of 2007. In developing the implementation plan, the Board considered the technology to be used, how smart meter systems will be procured and by whom, and who should pay for the systems. A number of constraints influenced the plan including the evolving structure of the electricity distribution system in Ontario, the need to begin implementation promptly to meet the government's target installation dates, and a desire to minimize the overall cost of the smart metering initiative. The more significant issues covered in the implementation plan are summarized below.

Proposed smart meter system

The Board proposes a basic smart metering system in Ontario that would measure how much electricity a customer uses each hour of the day. Through wireless communication or other technologies, the data would be transferred daily to the local electricity distributor. The distributor would use that data to charge customers an energy price that varies depending on when the electricity was consumed. Customers would have access to data by telephone or Internet the following day. Distributors would transmit customer consumption data to retailers for those customers who had signed with retailers.

The proposed smart meter system would support current methods of charging larger customers. Some larger commercial and industrial customers pay delivery charges based on their maximum electricity demand or based on their power factor (rather than on total consumption, which is the basis used to determine the delivery charges for residential and smaller commercial customers).

The implementation plan does not propose to mandate a specific system or a particular vendor. The type of system that is best for any distribution area depends on many factors, particularly customer density and geographic factors. Each electricity distributor will have to determine what works best in its area, as long as the system selected meets the minimum technical standards proposed by the Board. Given the need to move quickly, the Board is proposing that distributors adhere to the guidelines for vendor selection. See section 4.4.1.

The basic smart meter system proposed by the Board is based on two-way communication (data transferred to and from the meter by the distributor). It should be noted that two-way communication is not, in itself, sufficient to provide functions such as customer display, integration with load control systems, interface to smart thermostats, voltage monitoring, earlier payment, load limiting and remote cut-off. These functions depend on the availability of ancillary devices at additional cost. In order to improve interoperability and the development of ancillary devices, the Board proposes a requirement that smart meter systems have an open network interface at the connection to the wide area network.

The Board expects that retailers and other energy services companies will be prepared to offer enhanced services for a fee to those customers who desire extra functionality as it becomes available on these systems.

Rollout of smart meters

The implementation plan proposes that all new and existing customers of licensed distributors in Ontario, including all residential and small commercial customers, have some type of smart meter by December 31, 2010. General service customers with peak electricity demand between 50 and 200 kW will get a smart meter capable of reading demand (which is required to compute demand charges applicable to those customers). General service and industrial customers with over 200 kW of peak demand (maximum electricity use at any point in the month) will get interval meters that measure consumption in 15-minute intervals.

In all areas of the province, large customers that have peak demands over 200 kW will get new meters first. These meters can be installed quickly because the meters will be the same as the ones already used by many industrial customers.

For all other customers, the Board proposes a two-phased plan that focuses on the large urban distribution companies until the end of 2007 and the remainder of the province starting in 2008. This approach focuses efforts in such a way that the 2007 target of 800,000 meters installed is achieved while minimizing technology or implementation risks that could threaten the overall success of the initiative. The advantages of this approach range from better project planning and control to the opportunity to test economies of scale thresholds and to prove technologies. Because the large urban distributors collectively serve more than 40% of customers in the province, it would be capable both of achieving the 2007 installation target and providing a diverse but controllable pilot deployment from which the Board and other distributors can learn.

Once these large urban distributors have selected their smart meter systems, industrial and commercial customers with peak loads from 50 kW to 200 kW will receive smart meters and all new installations (such as meters in newly constructed homes) will have smart meters.

The meters recommended for residential and small commercial customers are not interval meters and their readings are not collected over dedicated telephone lines. Rather, a full range of public and private Wide Area Network (WAN) infrastructure communication media is available for mass-deployed systems including wireless radio frequency, power line carrier, and shared telephone transmission to send information to and from the meter.

In the second phase of the implementation, the balance of the distributors in the province would choose and install smart meters for commercial and residential customers. It is expected that the lessons learned and systems implemented in the first phase will significantly ease the later installations.

The Board is encouraging distributors to carry out an initial set of pilot programs using dedicated conservation and demand-management funds during 2005 to gain useful information about the installation and operation of smart meter systems before making final decisions on the particular system that they intend to choose. The Board expects distributors who have held pilot projects to share lessons learned with other distributors.

Responsibility for implementation

Five parties will have key roles in the implementation process. The Board proposes the following breakdown of responsibilities for each:

Ministry of Energy

Our plan proposes that the Ministry of Energy should retain responsibility for policy decisions over the life of the project. The Board also proposes that the Ministry should develop and guide the communication process to ensure electricity consumers in the province have a clear understanding of the objectives of smart metering and the need to develop a conservation culture.

Ontario Energy Board

The Board should be responsible for setting up a regulatory framework for smart meters; reviewing distributor procurement and deployment plans for prudence; preparing appropriate rate plans for use with smart meters; amending codes governing metering and the activities of distributors; amending distributor licence conditions and rate applications to include smart metering costs; and, where appropriate, setting province-wide standards for distributor business processes, such as data presentment to customers.

Distributors

Distributors should be responsible for selecting a smart metering system that best suits their regional conditions and customer mix. As they are now, distributors will continue to be responsible for the installation, servicing and reading of the meter.

The Board has concluded that distributors should be responsible for procurement and installation of smart meter systems because of their long-standing role in metering in Ontario, their knowledge of their customers and service areas, and the critical interface between the smart meter system and a distributor's own billing and settlement systems. The Board believes, however, that it would not be cost-effective to have approximately 90 distributors acting independently in their selection and procurement of smart meter systems. Therefore, the Board is proposing that distributors form voluntary buying groups to select and procure smart meter systems. Some distributor buying groups already exist for buying distribution equipment and other goods. Their expertise should be leveraged.

Group procurement by the large distributors will test the threshold for maximum economies of scale in purchasing smart meters. The results of these procurement processes will permit the Board to provide guidance to other distributor buying groups in the second phase of the project and will eliminate the need to have all distributors form buying groups immediately.

Focusing initial procurement of smart meters in the large urban distributors' areas will also permit testing vendor response to system specifications particularly the requirement that vendors provide access to their proprietary systems for other vendor equipment.

Program Coordinator

The Board should have overall responsibility for managing the smart meter project but proposes to hire a Program Coordinator to oversee the implementation process, to monitor progress, and to coordinate the activities of distributors over several years. This Program Coordinator would operate under the direction and authority of the Board and report to the Board.

Independent Electricity System Operator (IESO)

The IESO should identify constrained areas for priority installation of smart meters and monitor the power system and initiate formal critical peak calls on a provincial basis as required from time to time. In the future, these critical peak calls may signal the application of critical peak pricing periods.

Vendors

Vendors wishing to introduce new smart meters to the Ontario market should complete the Measurement Canada approval process and acquire the appropriate permissions for any radio frequency licences required. They may also need to make product adjustments to allow for an open interface for system interoperability.

Impact on customers

Two things will change for electricity customers with smart meter systems. They can receive timely information on consumption and distributors will offer pricing plans that will feature electricity pricing that varies by time of use.

The Board proposes that customers have daily access to their consumption data for the previous day via the Internet or telephone or, for an additional fee, with an in-home customer display. Historical consumption data will also be available. Customers will have information on how much energy they consume during different hours and different days.

The Board is currently developing a regulated price plan that will be available to residential and other customers to be designated by the government. It is expected that the regulated price plan for customers with smart meters will feature prices that vary by time of use. The combination of a smart meter and a “smart” price plan means customers will have the incentive and the ability to control their energy costs through moving usage to off-peak periods (for example, running the dishwasher at night) or lowering energy use during peak periods (such as setting the air conditioning a few degrees warmer during the afternoon). Customers will be able do this manually, by using automatic control devices that they purchase and install themselves, or via a contract with an energy services company to control devices automatically based on price or demand level over the system. Customers will pay according to what they use and when they use it. And those who conserve will not subsidize those who do not.

The Board’s regulated price plan may at some later date also feature special pricing for critical days when the electricity system is at capacity and wholesale commodity prices are very high. These are usually hot summer days when air conditioners are running on full or evenings during cold snaps when heaters, ovens and lights are all in use. While there are usually no more than 15 events like this each year, electricity at these times can be very expensive. The IESO would issue critical peak call to signal that the following day will have critical peak pricing. Customers would be alerted by the broadcast media, such as radio and television and Internet, that prices will be high for that day. Customers with smart meters will be able to save by cutting back their use during those critical days.

Higher peak winter prices can have significant cost impacts on those customers who rely on electric heat and have limited ability to shift demand. Conservation programs may focus on support for mitigating technologies like thermal storage, heat pumps or conversion to natural gas heating.

Larger commercial and industrial customers that have not signed with retailers currently pay the hourly wholesale spot price for their electricity. If they do not have interval meters, they are charged based on a system-wide load profile, which may have little resemblance to their actual hourly consumption. With smart meter systems, they will pay the hourly price on their actual hourly consumption.

Cost

The implementation plan proposes that the capital and operating costs of the smart meter system be included in a distributor's delivery rates that are charged to all customers in a particular rate class, whether or not they have a smart meter. In addition, it proposes that the costs related to old meters and other distributor assets that are made obsolete by the introduction of smart meters continue to be included in distribution charges.

It is proposed that costs be included in the distribution rate as soon as a distributor starts to install smart meters. Because it will take several years to complete the installation of smart meters in a distributor's area, the impact on customer bills will be small initially. It will rise as the implementation program progresses. In the initial period, the incremental costs will include some data management and billing system changes that are needed for all customers and a portion of the meter and communication infrastructure. Initial stranded costs will be low since most of the existing meter and equipment used for manual meter reading will remain in service for several more years until it is all finally changed out by 2010.

The total capital cost through to 2010 for the proposed system (meter, communications, installation and distributor system changes) is estimated at $1 billion. The net increase in annual operating cost for the province, when all meters are installed, is estimated to be $50 million. Eventually when the project is complete, the cumulative costs might require a monthly charge of between $3 and $4 to cover capital and operating costs.

The cost estimates in the preceding paragraph, and in the report, are for illustration only. The Board sets electricity distribution rates through transparent public processes and has not yet set any rates that include the cost of smart meters.

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1. Introduction and Paper Overview

1.1 The Directive

On July 16, 2004, the Ontario Energy Board received a directive from the Minister of Energy under section 27.1 of the *Ontario Energy Board Act*, *1998*. The Minister directed the Board to provide a plan to implement smart meter targets. The policy of the Government is to install 800,000 smart meters by December 31, 2007 and for all Ontario customers by December 31, 2010.

This project has been assigned Board file number RP-2004-0196. The full text of the directive is available as Appendix A-1.

1.2 Objective

The government has said that it is desirable, through the installation of smart meters, to manage demand for electricity in Ontario in order to make more efficient use of the current supply of electricity and to reduce the province's reliance on external sources.

The Government asked the Board to consult with stakeholders on options for achieving the smart meter targets including mandatory and optional technical requirements.

The Board's aim was to develop the most effective and workable plan to achieve the government policy objective on smart meters and conservation. The Board tried to balance costs and benefits and to be fair to ratepayers, distributors and competitive companies. At the same time, the Board has recognized that an investment of this scope is a unique opportunity to lay a foundation for future electricity industry services and prepare for future customer information needs. By setting minimum standards, the Board has also left the door open for distributors and others to add enhanced function at extra cost where a business case supports this.

In developing the plan, the Board has seen evidence that the smart meter initiative is both challenging and complex yet feasible. The timelines are aggressive and will require a high level of cooperation between key players involved over several years. Resources, particularly during the first phase until the end of 2007, may be limited due to competing electricity initiatives.

The breadth of the implementation will make Ontario unique in North America by being the first to:

- automate the reading of all meters as well as reprogramming read periods using two-way communication within a region with multiple distribution service areas;
- ensure that the system is capable of recording hourly data for every customer; and

- provide previous day's usage information to all customers so that they can review and understand billed energy based on consumption.

Smart metering is important for better energy use because it permits matching of consumption with the true cost of electricity that can vary significantly with daily and seasonal peak demand. Because smart meters measure both how much electricity is used and when it is used, they give consumers the information necessary to control usage during peak periods when the price is high. Conservation behaviour during peak periods can, in turn, reduce the amount of electricity generation needed in the province and thereby lower costs for all. See Appendix A-2 for further background and a discussion of how load shifting affects commodity price.

1.3 Approach

After receiving the Minister's directive, the Board prepared a discussion paper that outlined the major issues and asked for comments. The Board received 43 papers reflecting diverse viewpoints.

The Board then invited stakeholders to participate in working groups. The Board formed four working groups: Metering Technology; Communications and Data Interface Technology; Planning and Strategy; and Cost Considerations. These groups met many times between September 1 and October 14, 2004. Each group developed discussion papers, reports and recommendations for the Board to consider in developing the implementation plan. The Board wishes to thank all participants in the working groups for their contribution of time, experience and insight. For a list of organizations represented on the working groups, see Appendix A-3.

In response to the request for comments on the draft implementation plan released November 9, 2004 , the Board received 57 submissions from stakeholders and 26 replies from individual ratepayers.

After reviewing those comments, the Board concluded it should investigate the feasibility of standard data protocols and a single operator to coordinate the deployment and operation of the communication system. The Board received 34 responses to a request for additional information on these issues.

The Board has considered the comments from all respondents in finalizing the plan for the Minister. Significant comments raised in all stages of the consultation are discussed where appropriate throughout the report.

The Board also commissioned a survey of current meter inventories and practices of local electricity distribution companies in Ontario. The data from that study have helped with overall estimates of costs, benefits and targets. For the complete consolidated report, please see Appendix A-4.

1.4 Structure of the Report

This section of the document describes the implementation plan for smart metering. Section 2 is the implementation plan including roles and responsibilities, timelines, implementation approaches and deployment priorities. Section 3 outlines overall project costs and benefits, stranded costs and the proposed cost recovery approach. Section 4 contains the technical specifications for smart metering systems in Ontario. Section 5 discusses other potential non-commodity time of use rates. Section 6 outlines the next steps in the implementation.

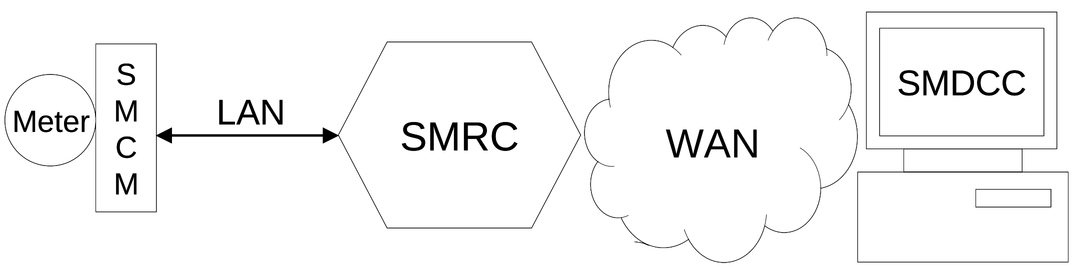
The appendices include a glossary of terms and acronyms, background information and further details of the implementation plan.

1.5 Definition of Smart Meter Terms and System Components

Figure 1 and definitions in this section describe a generic smart metering system.

Figure 1. Typical Smart Meter System Configuration

SMS Component Definitions



SMS – Smart Metering System
SMCM – Smart Meter Communications Module
SMRC – Smart Meter Regional Collector
SMDCC – Smart Meter Data Collection Computer
WAN – Wide Area Network
LAN – Local Area Network

Smart meter vendor systems vary considerably in their infrastructure setup and may not match this diagram (for example, SMCM may connect directly to the WAN, SMCM may be housed in the substation, etc.)

1.5.1 Meter

All electricity meters measure the consumption of electricity. A meter may be fitted with a register and display from which cumulative consumption can be read.

A meter may also record current and previous consumption in its memory for later retrieval. Readings stored in memory are time-stamped with the date and time the reading was taken. Readings may take the form of accumulated energy consumption or the actual energy consumed in the interval between readings.

A meter may be directly connected to the main supply through the use of a sealed socket. These are typically installed outdoors. For higher voltage applications, meters are usually isolated from the main supply through the use of instrument transformers and are secured in a locked meter cabinet.

1.5.2 Smart Meter Communication Module (SMCM)

The communication module is a communication device housed either under the meter glass or outside the meter. It takes the information from the meter and transfers it through the system to the collection computer. The system may not have memory in the meter or in the communication module. Information that is not stored in resident communication module memory, may either be transferred at a pre-programmed time for storage in an intermediary collector device, or sent directly through the WAN to the collection computer. The communication module may also be able to receive information and be reconfigured remotely by the collection computer using a two-way communication link.

Loss of communication to the communication module may mean loss of data. This can be reduced or eliminated by specifying adequate redundancy.

1.5.3 Local Area Network (LAN)

The LAN is the communication link from the communication module to the regional collector. Traditionally, the LAN is designed to carry information over distances of less than 1.5 km.

1.5.4 Smart Meter Regional Collectors (SMRC)

The regional collector can store data from the communication module as well as transmit it to the collection computer. If the communication module has little or no memory, the regional collector may act as the memory and storage point for the data, and in some cases completes the date and time stamping of the read data. The regional collector is the link between the LAN and the WAN, bringing data from the communication module in the meter to the data collection computer.

1.5.5 Wide Area Network (WAN)

The WAN is the communication network that transmits meter reads from the regional collector to the data collection computer. In some systems, the WAN extends from the communication module directly to the data collection computer. WANs are designed to transmit data over long distances, traditionally greater than 1.5 km.

WANs transmit via fiber, telephone or radio frequency over a utility-owned private network or a third party owned communication network.

1.5.6 Smart Meter Data Collection Computer (SMDCC)

Usage data is retrieved and stored in the collection computer. Depending on the level of sophistication of the Smart Meter System, the collection computer will issue operation/status reports following the download of data every 24 hours.

The collection computer is also the central control point for registering new modules and accepting their data retrieved from the meter. As well, it connects the meter data to the distributor customer database, data repository and customer information system. It is the central control point for all two-way communication module programming including adds, moves, changes and programming of new time periods in the meters, whenever necessary. It also issues system status indicators and generates reports on the overall health of the system network and data collection operations.

2. Implementation

2.1 Overview

Achieving the Government's targets for smart metering systems will be a challenge. It will require an intense and well-coordinated effort by the Ministry, distributors, the Ontario Energy Board, the Program Coordinator, retailers and Electronic Business Transaction hubs as well as the cooperation of customers.

2.1.1 Current Installed Metering

At present, distributors have responsibility for the meter. This includes specification, service, reading and complying with Measurement Canada requirements for registration, data storage and re-verification. As of 2002, there were roughly 20,000 interval meters installed for large commercial and industrial customers in Ontario. In addition, there are approximately 50,000 customers with peak monthly demand over 50 kW that have three-phase meters with a demand pointer. The majority of the remaining 4.3 million Ontario customers have single-phase accumulation meters that register energy use. The distributor calculates consumption by taking the difference between the current and the previous reading.

2.1.2 Customer Categories

For the purposes of this implementation plan, customers have been categorized into three groups.

Table A: Customer Groups

Customer Group	Customer Segment
1	Residential and General Service with peak demand under 50 kW
2	General Service with peak demand between 50 kW and 200 kW
3	General Service with peak demand over 200 kW

General service customers above 50 kW demand presently total about 50,000 while general service under 50 kW customers total about 350,000 and residential customers about 3.9 million.

2.1.3 Phased deployment

In all areas of the province, distributors would have to install interval meters for all Category 3 customers by the end of 2007 These meters can be installed quickly because the meters will be the same as the ones already installed by many industrial customers.

The pace of change in electronic and telecommunication devices is rapid. Most stakeholders agree that it is not possible in 2005 to envision, much less specify, what will be the optimal technology to install in 2010 or even perhaps 2008. Today, no one available technology is appropriate or cost-effective in all situations.

For Category 1 and 2 customers, the Board proposes a two-phased plan that focuses on the customers of large urban distribution companies until the end of 2007. The Board is defining large urban distributors as those that have over 100,000 customers in a contiguous, compact service area.

This approach focuses efforts in such a way that the 2007 target of 800,000 meters installed is achieved while minimizing technology or implementation risks that could threaten the overall success of the initiative. The advantages of this approach range from better project planning and control to the opportunity to test economies of scale thresholds and prove technologies. Because this group represents more than 40% of customers in the province, it would be capable both of achieving the 2007 installation target and providing a diverse but controllable pilot deployment from which the Board and other distributors can learn.

In phase two of the project, the balance of the large distributors' customers and all Category 1 and 2 customers of small and medium-sized distributors would get smart meters by December 31, 2010.

2.2 Implementation Roles and Responsibilities

In its November 2004 draft plan, the Board had proposed an implementation coordinator to oversee the deployment process. While most stakeholders agreed that the activities proposed to be carried out by the implementation coordinator would be necessary, they objected to another bureaucracy or another layer of oversight between the Board and distributors. Distributors, in particular, felt that it added an element of uncertainty to procurement and cost recovery. The Board proposes that the Ministry of Energy and the Board undertake the activities previously identified as the responsibility of the implementation coordinator. This is reflected in the discussions below.

2.2.1 Ministry of Energy

The Board recommends that the Ministry have responsibility for major policy decisions over the life of the project. This would include developing and guiding the communication process to ensure electricity consumers in the province have a clear understanding of the objectives of smart metering and the need to develop a conservation culture. While each party will have responsibility for its own communication effort, the Board recommends that the Ministry set communication goals and identify common messages.

2.2.2 Ontario Energy Board

The Board’s role in implementation is to review distributor procurement and deployment plans for prudence and consistency with smart metering objectives and other Government policies yet to be developed that relate to metering. It will amend regulatory instruments and run stakeholder working groups to develop detailed standards for supporting processes. To meet the targets set in the directive, the Board has already commenced some activities, as authorized in the Minister's directive, such as drafting code amendments for the installation of interval meters for customers with demand greater than 200 kW.

The OEB would also investigate reports of non-compliance made by the Program Coordinator, whose role is described in the section 2.2.4, and take appropriate action.

2.2.3 Local Distribution Companies

The Board recommends that distributors continue to be responsible for metering service. This means that distributors would be tasked with all aspects of implementation within their service areas, including procurement, logistics, resourcing, deployment and communication. The Board recommends that distributors organize themselves into distributor buying groups for procurement of smart meters and that procurement plans be submitted to the Board for review and approval. They would have to respond to requests from large customers for early scheduling of meter installations and additional functionality in a timely manner. They would report their progress to the Board through the Program Coordinator. Distributors should also consider the group approach for other implementation tasks that might be more efficiently carried out through group action.

The Board analyzed a number of alternatives for metering service provision. One option was full customer choice in meter provision and services (contestable supply). The Board has not recommended that approach because there is currently insufficient quantitative evidence available to the Board that shows that opening metering to competition would provide enough benefits to justify removing it from monopoly control. The experience in the US suggests that competitive metering has not realized significant benefits to consumers. There is also a concern that this approach might slow down the rate of smart metering deployment during the transition period.

Another option suggested to the Board was the creation of a provincial network operator to own and operate the communications system for reading smart meters. The Board asked for additional comments on this subject in December of 2004. The consensus of those responding with comments was that distributors should be responsible for the LAN portion of the communication system needed for meter reading and that a public WAN portion of the system was already in place in most parts of the province often employing more than one technology. Since distributors would most likely use these WAN facilities in any event, the creation of a network operator to manage the "last mile" was not seen as having sufficient benefits to justify its creation. A network operator would also raise issues around expropriation of distributor business assets and would not relieve distributors of the legal responsibility for meter accuracy and meter data prescribed under the *Electricity and Gas Inspection Act*.

For a more detailed analysis of the options see Appendix B-1 (*Alternatives to Metering Remaining as a Regulated Distribution Function*).

2.2.4 Program Coordinator

The Program Coordinator would push for the progress needed to meet provincial targets. Distributors would provide updates on their progress and costs on a quarterly basis to the Program Coordinator who would in turn report progress to the Board. In the event of distributor non-compliance, the Program Coordinator would make every effort to help distributors to get back on track. It would bring together and chair a steering committee made up of key stakeholders to resolve issues that parties might otherwise have difficulty in resolving themselves. For other options considered for provincial coordination, see Appendix B-2 (*Provincial Coordination and Distributor Compliance*).

2.3 Implementation Timeline

Many stakeholders expressed concern over the aggressive timetable for the initiative. They cited concerns that it would cause mistakes to be made and drive up costs to meet arbitrary deadlines. In particular, many distributors noted the number of electricity sector initiatives concurrently under way and stated that their available resources may not be able to keep up. The Board has taken that into consideration in recommending the two-phased approach focusing on large urban distributors in the short term. Most of the rest of this discussion concentrates on the first phase of deployment.

Figure 2 provides an overall timeline to meet the December 2007 provincial target of 800,000 customers with smart metering. The dates specified are "no later than" dates. The chart is broken into workstreams for the Ontario Energy Board, the Program Coordinator and large urban distributors. These are:

Ontario Energy Board:

- **Consultation** includes the completion of the consultation process by obtaining feedback on the implementation plan from interested stakeholders and the broader public, finalizing the report and submitting it to the Minister of Energy. With the submission of this report, this process is now complete.

- **Regulatory** includes reviewing and approving distributor procurement and deployment plans for smart meters and amending rules, codes and standards. The Board follows an open and transparent process of notice and comment periods to amend rules and codes and issue rate orders. Amendments may be made to the Distribution System Code, the Retail Settlement Code, the Affiliate Relationship Code, the Distribution Rate Handbook, licence conditions and rate orders. Critical amendments to these regulatory instruments are to be completed by May 31, 2005. Approval of distributor plans will be ongoing throughout the project.

- **Provincial Standards for Supporting Processes** involves developing a provincial design baseline that would include such things as bill and Internet presentment standards, settlement standards and rules, editing and rebuilding standards for data, and XML data standards and communication standards. The Board will also give further guidance on drafting requests for proposals and contracts. These are to be completed by May 31, 2005.

Program Coordinator:

- **Provincial Coordination and Project Management** involves the Board hiring a Program Coordinator, setting up a steering committee, developing required business processes and systems for the Program Coordinator, overseeing distributor and EBT implementation progress, and resolving issues that hinder progress. These activities continue through the life of the program. The Program Coordinator should be hired by than March 31, 2005.

- **Communication** includes developing a detailed communication plan involving both pro-active and reactive communication. This plan will be based on direction from the Ministry of Energy and would involve Ministry, Program Coordinator, Board, and distributor communication efforts. These activities should begin by March 31, 2005.

- **Inter-Party Testing** of information transfer and billing systems is necessary to ensure that key players are ready to transfer metering data. The testing will be made up of two stages: scenario testing followed by operational testing. This process would start by May 31, 2006.

Local Distribution Company:

- **Business Processes** involve distributors designing new business processes to support their chosen technologies.

- **Smart Metering Deployment for Customer Group 3 (>200kW)** includes continuing to install interval meters using public and/or private telecommunication networks. This would begin in 2005 for all distributors because the technology involved is already proven and available.

- **Smart Metering Deployment for Customer Groups 1 and 2 (<200kW)** includes contracting with smart metering system vendors to organize technology pilots, organizing and training installation field staff and deploying meters and communication infrastructure for <200kW customers. These initial pilot projects have already begun in some distributor areas as part of Board approved conservation and demand management programs. Full-scale deployment of smart meters for Groups 1 and 2 will be focused initially in the large urban distributor service areas and should begin early in 2006. Deployment for Customer Groups

1 and 2 for all other distributors would not be mandated until 2008. Early adopters would be able to proceed if the Board is persuaded that their approach is prudent.

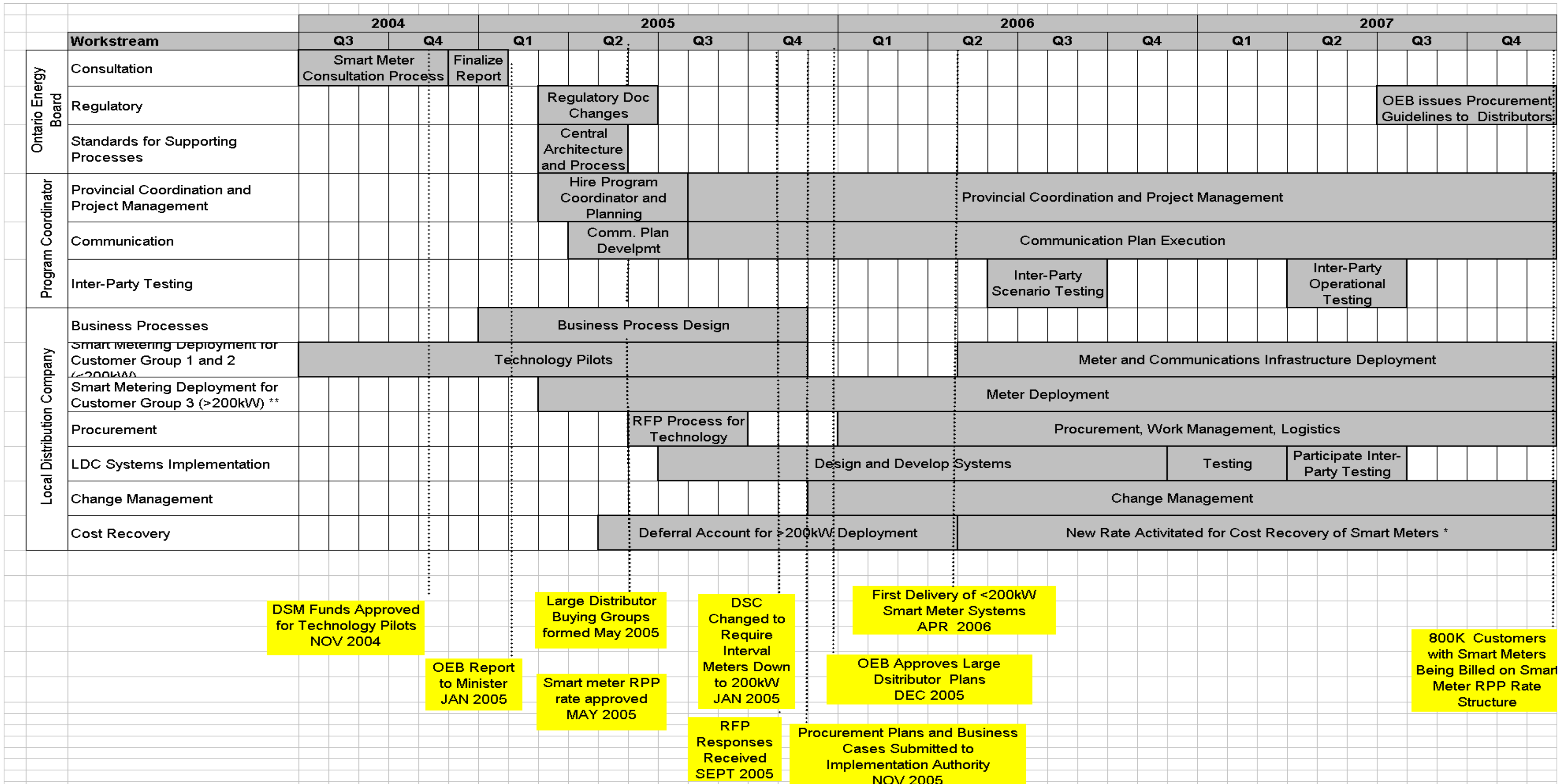
- **Procurement** focuses on distributor buying groups with common needs; RFP processes to obtain costs for required technology, development of business cases for functionality beyond the minimum requirements; Board review of procurement plans for prudence; negotiation of contracts with vendors; and logistics. Buying groups associated with the large urban distributors should begin the RFP process by June 2005.

  Other distributor buying groups should postpone procurement processes until the results of the large distributors' process are available and the Board has issued guidelines for buyer group size and prudence. This is expected to occur by early 2007. Distributors in this group who believe they have a compelling reason to begin deployment early may apply to the Board for approval to do so.

- **Distributor Systems Implementation** includes developing systems to support the smart metering technology, testing systems and participating in inter-party testing coordinated by the Program Coordinator. For the large urban distributors this should begin by June 30, 2005. Other distributors should postpone systems implementation to support smart metering until the experience of the large distributors is available and the Board is able to issue guidelines to assist them. Those distributors, other than large urban distributors, that have received Board approval to begin smart meter deployment earlier than 2008 should also begin systems implementation to support the early deployment.
- **Change Management** involves documenting business processes, policies and procedures, establishing performance metrics, training staff on new business processes and technologies and managing staffing changes. It would also include the distributor portion of the overall communication plan. This would begin no later than November 30, 2005 for the large urban distributors. Other distributors who will be deploying after 2007 may want to begin some of the change management processes earlier than that time but are not required to do so.
- **Cost Recovery** includes reviewing cost recovery processes of the Board, submitting and obtaining approval on rate applications, and implementing new rates that allow for the recovery of prudently incurred smart metering costs. This would begin as part of the 2006 Electricity Distribution Rates process currently underway.

For a more detailed breakdown of implementation tasks, see Appendix B-3 (*Preliminary List of Implementation Tasks*)

Figure 2: Smart Meter Implementation Timeline (start and end dates shown are "no later than" dates)



NOTES

* LDCs can start to bill on time based rates anytime after the rate is established but no later than December 2007 for groups of customers with smart meters. Cost recovery will begin when customers start receiving their smart meters.

** The implementation authority will not need to approve procurement plans for >200kW since there is an established process already in place for this customer segment and system functionality already exists for billing.

2.4 Procurement

2.4.1 Distributor Buying Groups

Ontario's varying customer density and terrain call for a range of systems. Distributors with similar needs should form buying groups and issue requests for proposals to help get the best pricing. Buying groups already exist for many equipment purchases, and new groups are forming to prepare for this and other initiatives. The large urban distributor procurement process is expected to establish benchmarks for procurement processes and provide insight into the minimum buying group size to achieve the desired economies of scale. Once this experience is available, the Board will issue guidelines for the balance of distributors to follow in setting up buying groups and issuing RFPs.

Forming these buying groups as part of this initiative may result in greater distributor cooperation in other areas as well. These buying groups are often naturally grouped geographically and according to similar system requirements. This would result in easier integration of meter systems in the event of regional distributor consolidation.

Buying groups may also contract for metering, communications, logistics / warehousing, installation and meter data services. Operations are similar between distributors and consolidation through cooperation or outsourcing are likely. Some stakeholders suggested that it would be cost effective to have one or more data management centres rather than have each distributor build custom applications. Although detailed evidence was lacking, it would appear to be intuitively obvious that such an approach would reduce costs. The Board would expect the large urban distributors to investigate the cost effectiveness of developing a coordinated application and/or outsourcing to a third party for applications such as data management, preparing CIS-ready files and customer presentment.

The Board considered options for procurement including a centralized RFP to award multiple vendors, a centralized RFP to award a prime contractor who in turn would contract with several vendors; and a solution unique to Ontario where a single technology would be developed that would work for all meters in the province. The following explains why these options were not recommended.

Alternative 1: Centralized RFP to Multiple Vendors

This option is similar to the recommended option in that both would involve a task force of distributors making technology decisions while being facilitated by the provincial Program Coordinator. The major difference is that a central RFP would not give distributors full accountability for the process and would be a very complex and slow process to administer with over 90 distributors.

Alternative 2: Centralized RFP to Prime Contractor

This option would pass the coordination responsibilities of provincial deployment over to a prime contractor. The prime contractor would contract with individual vendors to provide distributors with technology alternatives. The option would add an additional layer of costs. With only one contracting entity, a problem with the prime contractor would put the entire provincial project at risk. Contracting with a prime contractor would likely be very complex and would take a long time to set up.

Alternative 3: Customized Solution

Under the option for a unique solution, a technology would be developed specifically for Ontario to work for all meters in the province. It would ensure an appropriate level of rationalization and would achieve economies of scale. But it would require lengthy up-front analysis and development and would not be possible in the timeline set for the initiative. In working groups and comment letters, many meter manufacturers stated that the size of the Ontario market did not justify a customized solution. It would also place additional risk on the province and would likely require additional approvals by Measurement Canada. For a more detailed analysis of the options considered see Appendix B-4 (*Procurement Strategy*).

2.4.2 Procurement Process Oversight

With current technologies, more than one kind of smart metering system will be required in the Province and possibly within an individual distributor's service area. Distributor buying groups would need to be large enough to ensure that economic order quantities for individual systems could be achieved. This level is not accurately known at this time. However, the large urban distributors collectively have more than 1.5 million customers and procurement by this group is expected to yield data on the threshold necessary to achieve economies of scale. It is recommended that plans for the large urban distributors would need to be submitted to the Board no later than November 2005.

For 2007, the Board would oversee the formation of buying groups and the development of procurement processes to ensure that all distributors were included and that the groups met the objectives once the experience of the large urban distributors is available. The Board would develop guidelines on preparing plans and business cases. Buying groups would submit their procurement process for customers less than 200kW to the Board, which would assess the distributors' efforts to form buying groups and capture economies of scale. Distributors would follow their current process for buying interval meters for customers greater than 200kW and would not require approval.

2.4.3 Business Cases for Enhanced Functionality

Where a distributor intends to provide functions that go beyond the minimum standards described in Section 4.4 of this document, and seeks to recover costs through distribution rates, the distributor would have to submit a business case to the

Board. This case would not be needed if there were offsetting distributor-realized savings or customers were not charged for this functionality. Customer charges would have to be approved by the Board. The Board will develop detailed guidelines for business cases in 2005.

2.5 Deployment

2.5.1 Phase 1 – 2005-2007: Large Urban Distributors

Failed technology is one of the greatest risks to the smart metering initiative. In order to minimize this risk, the Board recommends implementing the Smart Meter initiative first in large urban distributor service areas where a focused effort can be better monitored and controlled. The advantages of focusing the initial deployment in this way are as follows.

- The Board and the Program Coordinator would be able to monitor and control the process with a limited number of deployment groups rather than all distributors acting at once.

- Project planning and control is likely to be more comprehensive and successful with large distributors because they have better expertise and more resources to deploy on the project than the smaller distributors.

- Mistakes in the procurement and deployment of smart meters will be easier to identify and correct in a few large deployments than in many smaller ones. The benefit of that learning experience can later be transferred to other distributors to help avoid repeating the same mistakes.

- The large urban distributors are sufficiently diverse that a range of technologies will likely be deployed thereby providing a reasonable test of the available systems before province wide deployment begins. Technology failures can be identified and either corrected or isolated so that the same product is not deployed elsewhere.

- The large urban distributors collectively serve more than 1.5 million customers. Achieving the deployment target of 800,000 by 2007 should be possible within their service areas and the threshold for maximum economies of scale in procurement should be testable before the balance of the meters across the province is deployed. Delaying deployment in the rest of the province provides time for manufacturers to develop new solutions that might otherwise not be developed if procurement decisions for all distributors are made at the outset of the program.

- Implementation in rural areas (eg. Hydro One Networks Inc. rural customers) would be postponed pending the outcome of the large urban deployment allowing more time to evaluate the cost/benefits and technology requirements for this sector.

- The large urban distributor implementation would give benchmark cost data on which the Board could base guidelines for subsequent meter deployments.

- These distributors are primarily in the congested areas of the province so the immediate benefit of relieving congestion at peak times would be maximized.

- Focusing on the large urban distributors for the initial deployment does not necessarily preclude other early adopting distributors from deploying smart meters before 2008. However, in order to control the process and ensure prudency, the Board will require these distributors to justify their early participation in the procurement and deployment plan review.

2.5.2 Phase 2 – 2008-2010: Medium and Small Distributors

The balance of distributors would begin to select and install smart meters for all group 1 and 2 customers from 2008 to 2010. The Board will revise the implementation plan for this phase to incorporate lessons learned, take advantage of new technologies, and build on the systems developed for phase 1.

2.5.3 Pilot projects

The Board has encouraged distributors to conduct pilots of a variety of vendor technologies and has approved a number of these as part of distributor conservation and demand management initiatives. These pilot projects should be completed by November 2005. Experience from these pilots will be incorporated into the planning by the large urban distributors for the initial deployment of 800,000 meters. The Board will use the experience gained through that initial deployment to formulate guidelines for subsequent deployments by all distributors.

2.5.4 Deployment Work Programs for Phase 1

Based on resource skill sets, distributors will have two parallel deployment work streams. The following chart specifies each work stream. Since the two streams use different types of resources, there is no priority given to one over the other. See Appendix B-5 for suggestions on task specific training for installers.

Table B: Work Programs for Customer Groups

Customer Group	Work Programs	Resources Used for Deployment	Low Cost Deployment Strategy	Number of Meters in Province
Group 2 and 3 >50kW customers and other three-phase metering	A	Certified meter technician	One off installations	Approx. 50,000
Group 1 Residential and GS <50kW with single phase metering	B	Installers with task specific training only	Mass deployment (distributor area sweep)	Approx. 4.3 million

2.5.5 Deployment in Congested Zones

Every year, the IESO publishes an integrated assessment of the security and adequacy of the Ontario electricity system over the next 10 years. Currently the IESO has identified three congested zones (Toronto, western GTA and northern GTA). The IESO has suggested demand reduction initiatives should target these areas. Since most of the large urban distributors are in the congested zone, the deployment strategy should give the maximum benefit in Phase 1.

2.5.6 Priorities in Meter Deployment

There is no strong evidence that any one Ontario customer group is a better focus for consumption shifting than another. Customer behaviour is influenced by commodity price plans, distribution rate structures and DSM programs but none of these have been studied in sufficient detail in the electricity industry to make reliable predictions about which customer group is likely to respond by shifting load.

Certain priorities, however, suggest themselves. Putting smart meters in new installations minimizes stranded costs. Early customer adopters - general service customers who request installation - likely have load to shift and will produce early benefits. Publicly funded buildings (often referred to as the MUSH sector because they include municipally owned buildings, universities, schools and hospitals) may benefit from the cost savings associated with load shifting so they should be targets for early deployment.

Below are the rankings for various customer groups that reflect these considerations. Small three phase customers are a lower priority because installation is costly, their loads are smaller and they may have more limited opportunity for response. The lowest priority is given to loads that currently have interval meters because, although they lack a communication link for next day feedback, customers are still able to interrogate them by telephone and acquire the consumption data necessary to manage load.

Table C: Work Program A for Large Urban Distributors

Priority	Group	Number of Meters
1	New installations, service upgrades and meter changeouts	Approximately 30,000
2	General Service >50kW customers without interval meters who request early installations	
3	Publicly funded buildings (MUSH sector)	
4	Remaining General Service >50kW without interval meters	
5	Residential and GS <50kW (multi-phase)	
6	General Service >50kW who had interval meters but do not meet minimum smart meter requirements	

In Work Program B, new installations are a priority. Installation of smart meters at these customer sites will likely occur on a neighbourhood by neighbourhood basis to minimize installation costs.

Table D: Work Program B for Large Urban Distributors

Priority	Group	Number of Meters
1	New installations, service upgrades and meter changeouts	Approximately 60,000 /year
2	Residential and GS < 50kW (single phase)	Approximately 1,600,000

For distributor meter statistics and estimates, details on rationale for distributor priorities and mass deployment suggestions, see Appendix B-6 (*Deployment Priorities and Individual Distributor Targets*).

2.5.7 Distributor Targets

To meet the provincial targets, each of the large urban distributors needs to complete the following by December 31, 2007:

- Deployment of 100% of smart metering systems for customers greater than 200kW starting in January 2005 (Work Program A)
- Deployment of 100% of smart metering systems for customers greater than 50kW but less than 200kW, starting after the approval of procurement plans by the OEB (Work Program A)
- Deployment of 100% of new installations, meter changeouts and upgrades starting after the approval of procurement plans by the OEB (Work Program A and B)
- Deployment of 40% of meters for residential and small general service customers <50 kW
- Completion of all support systems including data management system, CIS modifications, meter reading system and new interfaces into the EBT hubs.

Distributors may contract out any functions including meter ownership, reading of meters, and data management and presentment to service bureaus. The distributor keeps the responsibility for the meter. Using one or more third party providers of applications and services may be more cost effective than each distributor developing its own applications and infrastructure.

Figure 3 shows how these priorities can be translated into suggested targets for the province by year. Distributors may use these numbers as a guide to determine specific annual targets. The Board will consult with each of these distributors to set year by year targets.

2.5.8 Exceptions

While distributors will not be precluded from replacing any meter, a number of meters may not need to be replaced with smart meters. The Board would approve exceptions.

The criteria for exceptions should be:

- Cost-effective remote communications are not available; and
- The installations have minimal loads; and/or
- Installations are not easily accessible.

The Board recommends the following initial list of pre-approved exceptions:

- Railroad crossings;
- Traffic lights;
- Street lighting;
- Cable TV amplifiers;
- Temporary services;
- Bus shelters;
- Emergency lighting; and
- Telephone booths.

2.5.9 Grandfathering of Existing Installations

It is recommended that two types of installations be grandfathered if installed before the date on which the Minister approves a smart metering implementation plan.

<u>Existing Prepaid Meters</u>

There are about 2,000 prepaid meters in the province that do not meet the minimum requirements of a smart meter to be capable of reporting consumption data and to bill for critical peaks. These meters have been used to achieve significant reductions in demand among the customers using them and should be grandfathered. The meters are not able to bill based on Critical Peak Pricing (CPP). Different rates would need to be set up for this group that do not include CPP (when implemented).

Also, the meters currently installed, while having real time display of consumption and pricing, do not have capability for historical feedback. They are essentially accumulation meters with real time display. Since they are not read with any regularity, there is little information to support trending reports.

If these grandfathered meters need to be replaced, the meter should be replaced with a compliant smart meter. In some situations, this will mean that smart meter communications infrastructure will be underutilized until all grandfathered prepaid meters are phased out.

A smart meter could have the added function of prepayment.

Upgrading Existing Interval Meters

Existing interval meters that are being used without communication should be upgraded to smart meters. This would be done by adding the appropriate technology. The data pulse stream could be used to drive an external, automated meter-reading module or a dial-up data collection process. These are low priority.

2.5.10 Distributor Specific Mass Deployment Strategies

Distributors may present alternative deployment plans as long as they are consistent with the deployment priorities and meet the minimum requirements. Distributors should have the flexibility to manage their own deployments. Where these plans involve enhanced functions for meters or communications, a distributor that intended to seek cost recovery from ratepayers would prepare a business case to submit to the Board for approval. An example of an alternate plan would be the development of a WAN network that requires new, distributor-owned infrastructure.

2.6 Customer Choice and Impacts

2.6.1 Mass Deployment and Requests for Early Deployment

It is estimated that one-off installations of residential meters cost five times more to complete than a mass deployment. Allowing residential and small general service customers to request early meter installations would result in higher costs and grossly underused communication infrastructure. For example, a network capable of supporting hundreds of meters might only be supporting a few. This would load costs at the beginning of the program. It is not recommended that smaller customers be allowed to request early installation.

2.6.2 Customer Exemption Requests

Many stakeholders and ratepayers expressed concern over the lack of a cost/benefit analysis and felt that, in particular, smart meters would not be justified for low-volume customers.

However, in order to keep an accumulation meter, these customers would have to support the full cost of manual meter reading and system requirements such as the cost of computing a net system load shape. This might be more than the cost of a smart meter installation. Also, these customers would likely face a high fixed-price charge to cover realistic electricity commodity pricing. For these reasons, customer exemptions based on consumption are not recommended.

Figure 3: Deployment Targets

All Distributors	GS >50kW	New Installs / Upgrades (per year)	Meter Changeouts (per year)	<50kW and residential	Total Cust.
	Priority Groups for 2007 Provincial Target				
TOTAL	49,937	99,705	76,297	3,921,528	4,359,412

Assumed percentage of All				
Deployment - 2005	5%	0%	0%	0%
Deployment - 2006	20%	25%	25%	5%
Deployment - 2007	35%	30%	30%	12%
Deployment - 2008	15%	50%	50%	30%
Deployment - 2009	25%	100%	100%	20%
Deployment - 2010	0%	100%	100%	33%

Deployment Timeline

Customer Groups	2005	2006	2007	2008	2009	2010	TOTAL
GS >50kW	2,497	9,987	17,478	7,491	12,484	0	49,937
New Installs / Service Upgrades	0	24,926	29,912	49,853	99,705	99,705	547,597
Meter Changeouts	0	18,121	21,745	38,149	76,297	76,297	419,633
GS <50kW and residential	0	196,076	470,583	1,176,458	784,306	1,294,104	3,921,528
Total	**2,497**	**249,111**	**539,717**	**1,271,950**	**972,792**	**1,470,106**	**4,506,173**
Cummulative Total	**2,497**	**251,607**	**791,325**	**2,063,275**	**3,036,067**	**4,506,173**	
Provincial Target			**800,000**			**All**	

Monthly install rate	416	20,759	44,976	105,996	81,066	122,509

2.6.3 Group 2 and 3 Customers (>50kW) Requesting Early Installation of Meters

Since installations in this customer group will be more complex and will require a certified meter technician, they will be scheduled on a one-off basis, as opposed to mass deployment as with residential customers. Costs will therefore not increase significantly with early installation of meters, so customers who can benefit from changing their consumption behaviour should be able to begin immediately. The Distribution System Code should specify, for example, that distributors must install meters within 4-6 weeks of a request (except under extraordinary circumstances). Since there is minimal added cost for early installation, these customers should not pay any additional charge for early deployment. If the customer asks for enhanced functionality or requested off-hours installation, there might be an additional charge.

2.6.4 Group 1 Customers Requesting Early Installation of Meters (<50kW)

Customers in this group should not be allowed to request early installation because it would disrupt the mass deployment strategy of the distributor. This would increase costs and slow down deployment. Since LAN-based communication infrastructure would need to be set up for meters to work, communications infrastructure would be underused.

2.7 Key Success Factors

Appendix B-7 (*Potential Barriers and Mitigation Plans*) contains an assessment of the potential barriers to the smart metering initiative. Based on the assessment, a number of key success factors were identified:

Effectively Manage Customer Relationships

Customer co-operation and support are essential to achieve the goals. A careful and properly orchestrated communication and education plan that is consistent with messages at the local levels should be executed. Customers must be shown how using the new smart metering technology can save them money.

The Board recommends that the Ministry develop core messages and goals to be used by all the other parties.

Distributors should coordinate visits to customers' homes (e.g. to install meters) to minimize disruption to customers and better use distributor resources. Distributors should communicate deployment schedules to retailers for their customers to ensure that retailers can answer customer inquiries and manage their businesses. OEB codes should clearly state the distributor's obligations for early installation or enhanced functionality. By taking these steps, a number of risks will be mitigated. Customers will be educated on the technology, how it will affect them and its scheduled deployment.

The communications plan could include some of the following options:

- Ministerial announcement
- Mass communications
- Bill stuffers
- Distributor targeted communications
- Installation schedule information
- Six month follow-up
- Education in conjunction with the Regulated Price Plan
- Large customers communications

To minimize the overall cost of communications and to ensure that regulated entities participate to the fullest possible extent, branding and pre-printed materials might be centrally coordinated. Any customer education undertaken by regulated entities beyond their normal level should be considered for cost recovery.

A more detailed communications plan, including guidelines and materials should be developed after the Minister accepts the final plan. It should take into account the timing of distributor deployments. Communications related to the Regulated Price Plan and creation of a conservation culture should be coordinated with smart metering communications.

Ensure Timely Decision-making

A number of Ontario and federal organizations must co-operate on consistent and timely decisions and policies. The Board recommends that it hire a Program Coordinator as soon as possible and its first priority be to communicate required decision dates and the impact of missing deadlines.

In addition, the Program Coordinator should chair a steering committee of stakeholders to ensure that issues among agencies are resolved in a timely manner. Representatives of distributors, retailers, ratepayers, the Board, the Ontario Power Authority, the Canadian Radio-television and Telecommunications Commission, EBT Hub, the Electrical Safety Authority, Measurement Canada, the IESO and the Ministry of Energy should be invited to participate. This will reduce the risk of delayed decisions that would jeopardize timelines.

Make Effective Resourcing Decisions

Distributors are unlikely to have sufficient resources in-house to fully deploy smart meters. Many distributors outsource meter reading and servicing and have few or no personnel to assign to the deployment. In other cases, collective bargaining agreements may preclude some contracting-out arrangements for distributors. Distributors should review and understand options/agreements regarding temporary and contract labour and develop a resource plan to achieve their deployment targets. They should train resources using available training programs and facilities where appropriate, hire resources from external service providers when needed and/or develop inter-utility resource sharing arrangements where possible.

Clear and Consistent Regulatory Framework

A key concern for distributors will be recovering the cost of this large capital investment. The Board will need to develop clear cost-recovery policies and procedures. Submitting procurement and deployment plans to the Board for approval will provide distributors with some assurance that they are following an approved process and will reduce the financial risk of cost recovery.

2.8 Distributor Impacts

To help distributors understand the impact of this initiative on their business, Appendix B-8 (*Distributor Impacts*) includes distributor business process, system and staffing impacts and an illustrative systems architecture for data management and settlements. Since each distributor is different, the information provided in this section should be used as a guideline for further analysis.

3. Smart Metering Costs

The capital cost of installing smart meters for all customers in the province is estimated at $1 billion. Based on cost estimates prepared by working groups for the basic smart meter system being proposed, the incremental monthly cost for a typical residential customer may be between $3 and $4 a month once full implementation is complete in 2010. Because costs will be spread among all customers in a class from the outset of the project, the monthly charge will start low and increase to the $3 to $4 figure as more and more meters are deployed. For example, in year one of the project, much of the system changes and some of the common infrastructure may have been deployed but few of the actual meters, so a charge of $0.30 to $0.40 per month per customer would be sufficient to fund that part of the project. In year two the total deployment might reach 25% and the cost per month per customer would rise to $0.75 to $1.00 to pay for the cumulative investment. Eventually, all customers would have a smart meter and the cumulative costs might require a monthly charge of between $3 and $4 to cover capital and operating costs. The amount included in a distributor's rates will depend on the forecasted spending for that distributor. This estimate includes assumptions about the useful life of the equipment. Ultimately the Board will decide on an allowable depreciation rate for smart meters.

This chapter looks at:

- **Impacts:** identifies the benefits to various stakeholders from smart metering systems.
- **New Costs:** identifies new capital and OM&A costs attributable to smart metering.
- **Multi-Utility Applications**: describes the Board's attempt to encourage use of the network by gas and water utilities.
- **Stranded Costs:** looks at the equipment and systems that may be displaced by smart metering.
- **Cost recovery:** discusses the principles that should apply to recovering costs associated with smart metering and recommends some mechanisms for doing so.

3.1 Impacts

3.1.1 Customer Impacts

In order for any market to work efficiently, customers must be able to forego a product or service when prices are higher than they want to pay. For this demand response to be possible in electricity, customers must have three things: a price that changes with the real costs in the market; the ability to see the price and to take action; and the ability to have those actions measured in order to benefit financially.

The Board is currently developing a regulated price plan that will be available to residential and other customers to be designated by the government. It is expected that this new plan at some point will have prices that vary by time of use. The Board's regulated price plan may also feature special pricing for critical days when the electricity system is at capacity and wholesale commodity prices are very high. These are usually hot summer days when air conditioners are running on full or cold winter evenings when heaters, ovens and lights are all in use. Electricity at these times, usually no more than 15 events per year, can be very expensive. If the IESO calls a critical peak period, the alert can be sent by television, radio and print media. At a minimum, the distributor should add the information to the customer information call-centre and web-site, and institute a voluntary e-mail or auto-dial notification list. Customers will know these prices in advance and be able to act accordingly. The Board will consider over the next year what accommodation needs to be made for critical peak pricing in its regulated rate plans.

Customers will be able to control their consumption through moving use to off-peak periods (running the dishwasher at night) or lowering energy use during peak periods (setting the air conditioning a few degrees warmer during the afternoon). Customers will be able do this themselves, by using automatic control devices that they purchase and install themselves, or via a contract with an energy services company to control devices automatically based on price or demand level.

With a smart meter, customers will be measured on how much and when they use electricity. They will be billed according to that measurement and will be able to see, in a timely fashion, their use and how it affects their bill. The Board proposes that customers will have daily access to their consumption data for the previous day via the Internet or telephone. Customers will have information on how much energy they consume during different hours and different days. Historical consumption data will also be available.

The combination of a smart meter and a "smart" price plan means customers will have the incentive and the ability to take action. Customers will pay according to what they use and when they use it. And those who conserve will not subsidize those who do not. Customers with smart meters will be able to financially benefit by curtailing consumption during those critical days.

When these customers take action, the whole electricity system will see a benefit. Studies have indicated that when supply is scarce relative to expected demand, a reduction in demand of 2 to 5 per cent could reduce prices by half or more.[1] This is particularly critical during peak demand periods, when prices typically increase very quickly. It is important to remember that, because of the infrequency and short duration of the events, customers' total electricity bill savings may be less than 2 per cent. However, the system benefits of reduced demand near system capacity limits are large. Prices are lowered for all customers when some customers lower or shift

[1] Rosenzweig, Michael, et al. "Market Power and Demand Responsiveness: Letting Customers Protect Themselves". *The Electricity Journal*. May 2003.

demand. Uplift charges for congestion management and reserve capacity are also lower for all customers when the system peak is lower. This benefit is greatest when congested areas are targeted for deployment of smart meters to encourage load shifting behaviour by consumers.

Higher peak winter prices can have significant cost impacts on those customers who rely on electric heat and have limited ability to shift demand. Conservation programs may focus on support for mitigating technologies like thermal storage, heat pumps or conversion to natural gas heating.

Larger commercial and industrial customers that have not signed with retailers currently pay the hourly wholesale spot price for their electricity. These large commercial and industrial customers that do not have interval meters are charged based on a system-wide load profile that may have little resemblance to their actual hourly consumption. Once these customers receive smart meters, they will pay the hourly price on their actual hourly consumption.

3.1.2 Distributor Operational Savings and Retailer Opportunities

Smart metering holds potential benefits for other groups. Distributors, for example, can use smart meters to get data that may allow them to optimize distribution systems. Customer complaints arising from estimated reads should fall. Retailers can use smart metering data to design pricing options and load control services that customers might find attractive. Both of these groups should be willing to pay for the benefits that they realize from the smart metering system options that are beyond the minimum functions, and so that part of the cost should not accrue to the customer directly.

To fully realize benefits, both distributors and retailers will generally face additional costs. The remote disconnect/reconnect feature, for example, has been promoted as a smart metering benefit that will cut the costs of managing delinquent accounts. The technology is not necessarily dependent on smart metering because paging technology allows the same result by triggering a disconnect switch in a sleeve installed on the load side of the meter. Utilities can apply this device with electromechanical meters if they wish since it does not rely on an AMR system for communication. The reason for the small take-up is the cost.[2] Manual disconnection cost can range from $20 for a simple meter pull in a suburban utility to several hundred dollars for a disconnection at the transformer. But with only a very small proportion of customers ever disconnected[3], there would seem to be inadequate justification for universal deployment of remote disconnect capability. In addition,

[2] Remote disconnect devices range from $135 to $250 according to industry estimates. The ENEL project in Italy deploys remote disconnect in every meter but the meter is purposely built by ENEL for a 250 V secondary voltage that only requires a 60 amp interrupting capability. The comparable breaker in 120/240 V systems like Ontario would range from 125 amp up to 200 amp which is more costly.

[3] Based on informal surveying of distributors, disconnects involve less than ½% of customers. If remote disconnect was available and relatively cost free, distributors might use it more often to discourage delinquency, perhaps up to double the present disconnect rate.

year round use of the switch would require a load limiting attachment to accommodate the practice in Ontario of leaving a customer with some basic power during the winter season. Load limiting, if it could be made available in a remotely operable form, would increase the cost of the device even more.

In the retailer's case, load control services coupled with a firm price contract for power is a service offering that would probably be attractive to some customers. If an inexpensive customer communication system can be deployed to make this operational then retailers will likely offer the service. But if the service relies on increased functionality of the metering system then the same situation as above occurs. If that functionality is not a standard feature of the system, a retailer may not pay the additional costs on speculation that it could sell sufficient service contracts to make a return on its investment.

Distributor operating savings from smart metering, detailed in Chart 1, Appendix C-1 (*Benefits*), are estimated to total about $0.39 per residential customer per month.

Almost all distributor benefits of smart metering require a subsequent investment requirement to be realized. Chart 1, Appendix C-1 lists the benefits that were identified with some estimates of value and the offsetting cost to obtain the benefit. Analysis and calculations for these benefits are presented in the Chart notes to Chart 1 also found in Appendix C-1 (*Benefits*).

Several stakeholders mentioned the advisability of having a system capable of reading water and gas meters in order to spread costs and gain efficiencies in other utilities. The Board expects distributors to investigate mitigating costs for shared smart meter systems by cooperating with other utilities such as water and gas serving the same customer base.

3.2 New Costs

Smart metering costs for the new single-phase residential meter and communication system are expected to average $250 for each meter installed. This includes the costs to modify existing systems and provide new data storage facilities and data handling software. This represents $2.47 on the average monthly residential bill.

The cost of each meter will vary among utilities because of distributor geography, customer density, customer type and the communication technology. The above figure, therefore, should not be used to benchmark any particular utility, but rather as an overall budgetary target to guide the project.

The estimate also excludes new operating costs that are not now being incurred and will have to be accommodated in distribution rates. An example of these is meter re-verification costs. Electronic meters have to be tested more often than electromechanical meters, so the cost of ensuring accuracy will increase with smart metering. Operating costs for automatic meter reading systems can also be significant. As a general average, communication maintenance is estimated to be about 1% of the installed capital cost of the system. Data storage and management will become a much larger task for distributors than presently and the costs may be significant. Presenting smart metering data to the customer is another new cost that potentially might be large, depending on the frequency of updating information and the quality of the presentment. Daily access to the data adds to the cost.

Several stakeholders questioned the cost/benefit of daily feedback compared to less frequent and less costly methods. However, there are also studies that suggest real-time feedback is even more beneficial. The Board continues to recommend daily availability of use and price information as specified in the Minister's directive.

Small commercial customers with single-phase meters who are not subject to charges based on monthly peak demand are assumed to use the same meter as residential customers and will probably cost about the same. Larger commercial and industrial customers will need more expensive solutions to handle demand charges. The estimated cost of serving these customers will vary with the technology installed, but because there are relatively few of them compared to residential and small general service customers, their impact on overall deployment costs for the project will not be excessive. For example, even if all were fitted with the kind of interval metering now deployed to large customers, the cost would still be under $50 million.

All of the new costs associated with smart metering are itemized in Chart 2 in Appendix C-2 (*Smart Metering Costs*). Taken together, these costs are expected to add a further $1.42 to the average residential customer's monthly bill. This is somewhat offset by the estimated $0.39 per month in distributor operational savings.

3.3 Multi-Utility Applications

Several stakeholders mentioned the advisability of having a system capable of reading water and gas meters in order to spread costs and gain efficiencies in other utilities. The Board expects distributors to investigate mitigating costs for shared smart meter systems by cooperating with water and gas utilities serving the same customers. Otherwise, the Board notes that in cases where distributors are currently reading municipal water meters, electricity distributors converting to smart meters would require the water utility to make alternative arrangements for reading water meters.

Proprietary equipment and protocols may make it difficult for other utilities to make use of new communication infrastructure. Therefore, the Board is encouraging multi-utility use by requiring that electricity smart meter systems have an open interface at the remote end of the local area network. See section 4.3.2.

3.4 Stranded Costs

Most residential and small commercial customers in Ontario have electromechanical meters that record cumulative energy consumption only. These customers represent more than 95% of meter installations in the province. Although electro-mechanical meters can be retrofitted with an under the glass module to permit smart metering functionality, this would have to be done in a meter shop and the meter re-verified under Measurement Canada rules. The costs of retrofitting may be sufficiently high that distributors will not find the alternative attractive. Therefore, this report assumes that electromechanical meters could be rendered obsolete by the smart metering initiative. Some distributors have deployed electronic versions of the accumulating meter and these might be adaptable to smart metering systems without great expense.

Most large general service customers (> 50 kW) are on a thermal demand-type meter that records peak demand usage for the billing period as well as energy consumption. Some of these are electronic and may be retrofitted with a communications device to permit hourly reading, in which case there will be no stranding of these assets. However, most thermal demand type meters in service today are not electronic and will have to be replaced by a smart meter, resulting in some stranded costs.

The largest commercial/industrial customers have interval meters that record hourly usage and are interrogated by the distributor using telephone lines. These interval meters will be left in service and will therefore not be stranded.

Other stranded costs may arise from distributor systems that are incapable of operating in the smart metering environment. Chart 3, in Appendix C-3 (*Stranded Costs*), lists these potential sources of stranded cost.

Stranded costs will not be insignificant. The net book value today associated with meter hardware that will be made obsolete was estimated from survey data at $473 million, not counting the cost of removing and handling the old meters.[4] If this figure is adjusted for depreciation over the period 2005 - 2010 for the declining set of assets still in service over that period, an additional $66 million in depreciation would be charged against the book value. Therefore, the stranded cost will be approximately $407 million.[5]

There is a limited potential to reuse this hardware. Used residential meters are worth only about $20 on a resale basis despite the fact that their book value is much higher as a result of capitalization of installation costs and a lengthy depreciation period. The cost to prepare and ship them to potential markets might exceed their value considering that new residential meters can be purchased for about $40.

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[4] Removal and handling is assumed to be attributable to the smart meter installation but if it is to be shared then possibly $10 of meter removal costs might be recorded as stranded in the old meter – this would increase the stranded cost by about $43 million.

[5] Assume 15 years left on depreciation schedule and $473 million at 7% average cost of debt i.e. no rate of return assumed on stranded assets. Assuming the result is allocated on a volumetric formula based on consumption then 40% will be allocated to residential customers.

Three-phase meters used for General Service customers might be more readily redeployed, but given the number of smart metering conversions going on in the world, there may be a glut of used equipment available that would limit prices. Secondary voltages used in Ontario might also limit redeployment of these meters outside the province. For example, fixed range units operating at 600/347 V cannot be redeployed to the United States where the common voltage is 480/277 V. Although meters installed in the past five years are probably adaptable to other voltage standards, older ones are likely not to be. For these reasons, resale of Ontario meters is not expected to significantly offset stranded costs.

3.5 Cost Recovery Principles

There are three types of costs to be considered in the implementation of the basic smart meter system: capital costs for meters, communication, associated systems for data handling and installation; on-going operating costs for reading, service, and re-verification; and stranded costs. The capital and operating costs are incremental to current rates. The costs of shared services (associated systems and some communication infrastructure costs) come at the beginning of the project. All customers will end up benefiting from their use.

In evaluating recovery options, the Board considered four principles:

- Cost recovery mechanisms should be reasonable and timely;
- Allocation of costs should be fair;
- Recovery should promote economic efficiency and be related to benefits, where possible; and
- Recovery should be consistent among distributors.

The Board considered three ways to recover the incremental costs.

Despite the general benefits to society and the electricity system of the program, the Board rejected the idea of a general tax as not apportioning costs and benefits equitably.

The Board also rejected the concept of recovery through a capital contribution (upfront payment from customers) for most customers. It would create complexity around the treatment of common capital costs such as system changes and shared infrastructure. It would be a change from current practice for meter costs in residential and small commercial rate classes. It also does not address on-going operating costs. A customer could also end up paying for capital contributions more than once due to moving between distributor areas. Finally, it inhibits affordability (rate shock) by spreading costs over a short period rather than the used and useful life. As an example, a smart meter may have a depreciation period of 15 years.

The only option meeting the four principles was recovery through distribution rates. The two most likely methods are discussed in detail below.

For either method, a cost reporting and monitoring system is needed to evaluate cost prudence as the smart metering project is rolled out. The details of that system need to be developed over the next year as part of the 2006 Electricity Distribution Rate process. This process also needs to consider the appropriate depreciation period for capital costs to avoid burdening future ratepayers for the benefits enjoyed by current ratepayers.

Appendix C-4 (*Recovery of Smart Metering Costs*) discusses further options for cost recovery in fixed or volumetric charges. The Board needs to decide in a future rate case if customers incur costs and enjoy benefits equally or if those with higher use get greater benefits.

The rate implications of both new and stranded costs are subject to a future proceeding before the Board. That proceeding will be an open and transparent process with full opportunity for stakeholder input. The Board received many stakeholder comments that will be of assistance.

3.5.1 Recovery of program costs from all customers within a class

Under this option, distributors would forecast the capital and operating budgets for the entire project and the amount to be spent in each year, allocated to rate classes. Cost allocation according to classes is appropriate since different classes will have different meter costs, installation costs and stranded costs based on the complexity of existing and future equipment. The budget would be included in revenue requirement and rates for each class of customer for 2006 and beyond. Each year for each distributor, the Board would revisit the revenue requirement, the budget and the progress toward targets to adjust the incremental rates for the following year.

This spreads the cost of the program across all customers in a class. The capital costs of shared services are borne by all customers who benefit directly and indirectly. Distributors would get forward certainty of recovery for prudent spending. The portion of rates related to smart meters will be higher once all are deployed. The annual increment will depend on how many meters are installed in a particular year.

3.5.2 Recovery of program costs in each class only from customers with smart meters

An alternative is to add smart metering costs to the distribution rates only of customers who have had them installed. This is a more complex cost allocation exercise.

It is likely that the Regulated Price Plan will have two components: a fixed-price plan for customers with common accumulation meters and a time-dependent price plan for customers who have smart meters. In order to provide the proper bills, distributors would have to be able to differentiate between these customers. This will in effect create sub-classes of customers in each class, e.g. General Service accumulation-metered customers and General Service smart-metered customers.

Distributors would forecast project costs to be recovered in each year as part of revenue requirement. However, distributors would have to distinguish between shared costs and individual customer costs. It would be unfair to burden early smart meter customers with all the upfront system costs since the costs are being incurred for all customers to have smart meters. Distributors would have to either attribute a significant portion of shared costs to fixed-price customers or defer that portion of costs until those customers have smart meters. Deferral accounts increase future rates and should be avoided if possible. If they are used, they need to be disposed of in an annual review.

Each distributor would also have different rates for each of the sub-classes. These rate sub-classes would be in effect until the deployment is complete.

This approach is driven by the ratemaking principle that customers who will be the principal beneficiaries of smart metering should pay the cost. However, it ignores the price benefits to accumulation-metered customers as a result of load-shifting by smart metered customers.

3.5.3 Recovery of Costs for Customers over 200 kW

Currently the Distribution System Code requires that customers with loads in excess of 500 kW be provided with an interval meter and communication link for interrogating the meter at the distributor's cost. The distributor is expected to recover its costs for interval meter installations through its rates. For customers with loads below the 500 kW threshold who want to have an interval meter, the Code requires a distributor to provide one but specifies that the customer pay the incremental cost of the interval meter. Some customers have taken advantage of this option and have paid some or all of the costs for their meter and telephone connection. The Board will need to consider what, if anything, will be done to compensate those customers who have contributed towards the cost of their meters under the 500 kW threshold rule.

The Smart meter plan proposes to lower the 500 kW threshold to 200 kW so that the Board will also need to consider whether future customers falling below this new threshold who request an interval meter will continue to be required to contribute to its cost.

Because distributors will not have approved rates for interval meters that recognize the new lower threshold of 200 kW until 2006, a deferral account may be necessary to collect costs of early deployments of these meters under the smart meter implementation plan. This would apply to all distributors in the province under Phase 1 of the deployment.

3.5.4 Enhanced System Features

System functionality beyond the basic system may be installed, but the starting point should be that the party who benefits bears the incremental cost. If a distributor thinks an enhanced feature will benefit customers, then it will need to justify that benefit to the Board before being allowed to recover the cost from customers.

3.5.5 Stranded Cost Recovery

Stranded costs could be managed by transferring them out of ratebase and into regulatory assets. A rate equal to the depreciation expense that would have been charged, had the assets remained in service, should be used to allow distributors to recover their un-depreciated capital costs. Stranded costs could be separated by customer class and recovered accordingly. This will have no impact on rates, but will extend the recovery period for the assets to about 15 years and may limit rate setting flexibility during that period. Recovery can begin with the smart meter deployment as a uniform charge to all customers in each distributor rate class for administrative convenience and consistent treatment of all customers. Alternatively, it can be staged to coincide with the point at which a customer actually receives a smart meter, if causality governs when cost recovery begins. See Appendix C-5 (*Recovery of Stranded Costs*) for further discussion.

4. Smart Metering System Minimum Requirements

4.1 Customer Groupings for Minimum Smart Metering System Requirements

Customers have been segmented into three groups according to the data typically needed to apply current and potential rate charges and commodity prices. The base level requirements for the smart meter system are driven by the data required for billing. The following chart determines the customer groups and meter data requirements. Group 3 systems will be similar to the current Distribution System Code requirements for interval-metered customers.

Table E: Typical customer billing and data requirements

Customer Group No.	Customer Segment	Billing quantities	Meter Data Collection Requirements	Smart Metering System Specification
1	Residential and General Service < 50 kW	kWh	Hourly data Single-phase	See section 4.4
2	General Service 50 kW – 200 kW	KWh kW	Three phase hourly data with approved demand measurement in-meter	See section 4.4
3	General Service >200 kW	kWh kW kVA/kVAR	Three phase 15 minute interval data potentially with power factor	Remote interrogation by established distributor practice

The smart metering system specification is primarily for Group 1 and 2 customers. Groups 1 and 2 will use dedicated automated meter reading systems to collect meter readings. The meters in Groups 1 and 2 are typically not interval meters although they are capable of providing hourly data through the smart meter system.

Interval meters are normally used for Group 3 customers to record power factor (kVA) or reactive readings (kVAR). Interval meters are usually interrogated by the distributor using dedicated or shared telephone lines, or various public and private network options such as wireless and power line carrier.

There are a few customers who do not fit into these three categories including Group 2 customers billed on power factor and those with net meters, 2.5 element meters, and straight 600V meters. For a discussion of the technology appropriate for their circumstances and other specialized meters, please see Appendix D-1.

4.2 Meter Specifications

Under the *Electricity and Gas Inspection Act*, Measurement Canada approves meters for trade and defines and enforces minimum accuracy and re-verification requirements. Manufacturers and vendors must get approval of their product from Measurement Canada.[6]

The Board is recommending that a smart meter must have a read resolution of 0.01kW to provide granularity for settlement. See Appendix D-2 for the meter specification.

Additional smart meters and ancillary devices need to enter the Ontario market. Currently the Board believes that there may not be enough Measurement Canada approved devices to guarantee competitive bidding. Lack of approved devices could place the smart meter implementation schedule at risk.

The approval process may take between six months and two years depending on the level of innovation of the product and the number of vendors applying. The Board further notes that modules under the meter glass must be approved with each meter type used. Only the original meter manufacturer can apply for approval.

Vendors wishing to qualify new systems for the Ontario market must, as a first step, apply to Measurement Canada for approval. This should be undertaken at the earliest possible opportunity to avoid impact on the project schedule.

The Board anticipates that the availability of open interfaces to the communication network will spur the development of ancillary devices such as appliance load control, price signallers and real-time displays. However, this cannot be guaranteed given the size of the Ontario market relative to the North American market and the necessity of using more than one system type.

4.3 Required Smart Metering System Service and Information Flow

4.3.1 Minimum Smart Metering System Functionality

The Board recommends a minimum functionality for the system. The distributor must ensure that its chosen system adheres to the minimum requirements and that the information it collects can be delivered to the customer and retailer as outlined herein.

In their comments on the Board's draft implementation plan, many stakeholders said that bi-directional communication was important to establish the potential for load control in the future through a province-wide communication infrastructure. The IESO stated that bi-directional communication increases the ability to track consumption and corresponding price and facilitates real time responses to changes in

[6] www.mc.ic.gc.ca

prices and market conditions. It will also increase the linkages between wholesale and retail markets.

Ultimately, the Board believes that the smart meter system will be primarily a meter-reading and utility management system. Stakeholder comment suggests that developments in other areas such as ubiquitous Wi-Fi networks, Ultra Wide Band technology (UWB) or Broadband Power Line (BPL) mean it is unlikely that the meter will be the primary gateway for last mile access into residential homes. At the same time, two-way communications are advantageous to the meter system for utility management functions alone and to accommodate meter reading for gas and water utilities. The Board has also heard from stakeholders that such a significant investment should build in the most flexibility. Equipment manufacturers would then have the option of building on the existing system for standardization of peripheral devices such as smart thermostats, real-time displays, price-signal devices and other load controls.

Given these arguments and the fact that bi-directional systems are available at the same cost as other systems, the Board has determined that the network should be two-way. One concern with this specification was that it would limit the range of available meters and would eliminate viable systems from contention. The Board is confident that by specifying this minimum, manufacturers will make the necessary investment to increase the number of two-way meter technologies. The Board recommends that two-way communication be established as the minimum standard.

4.3.2 Open Access and Data Flow

Open communication standards are well established and widely available to would-be users. Open standards are essential to the success of any industry-wide technology initiative that involves multiple participants and requires disparate systems to communicate with each other. Open standard interfaces are the foundation for interoperability among different vendor products.

Proprietary standards are on the opposite side of open standards. Proprietary standards are vendor specific and their details are not in the public domain. In addition, these standards are only used and accepted by a specific vendor.

In between are open protocols whereby a manufacturer makes available, with or without a licensing fee, the information necessary for another manufacturer to communicate with a device.

Without open access customers are locked into vendor specific solutions.

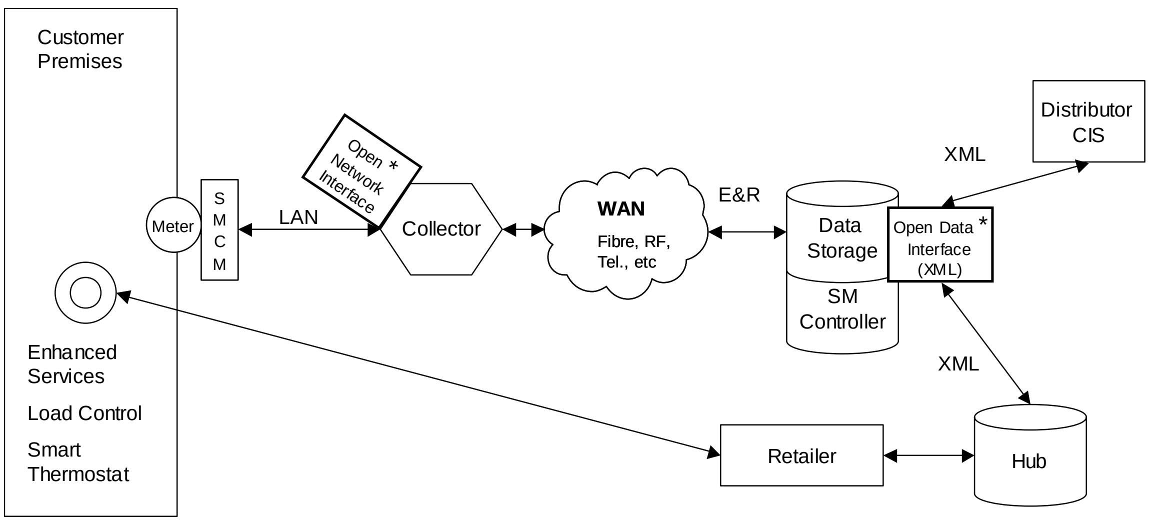
The smart meter system can be the basis of a province-wide communication system for the electricity industry. It is hoped that in the near future other services in addition to electricity meter reading could be offered using the smart meter network infrastructure.

Every smart meter solution has the following major components (figure 4):

- Smart Meter that generates raw data.
- LAN or Last mile, Collector and WAN networks that transport raw data from a Smart Meter to the data repository.
- Collection Computer that stores raw data and controls the Smart Meter System.
- Applications that process/convert collected data into useable information.

Figure 4: Smart Meter System Applications and Information Flow

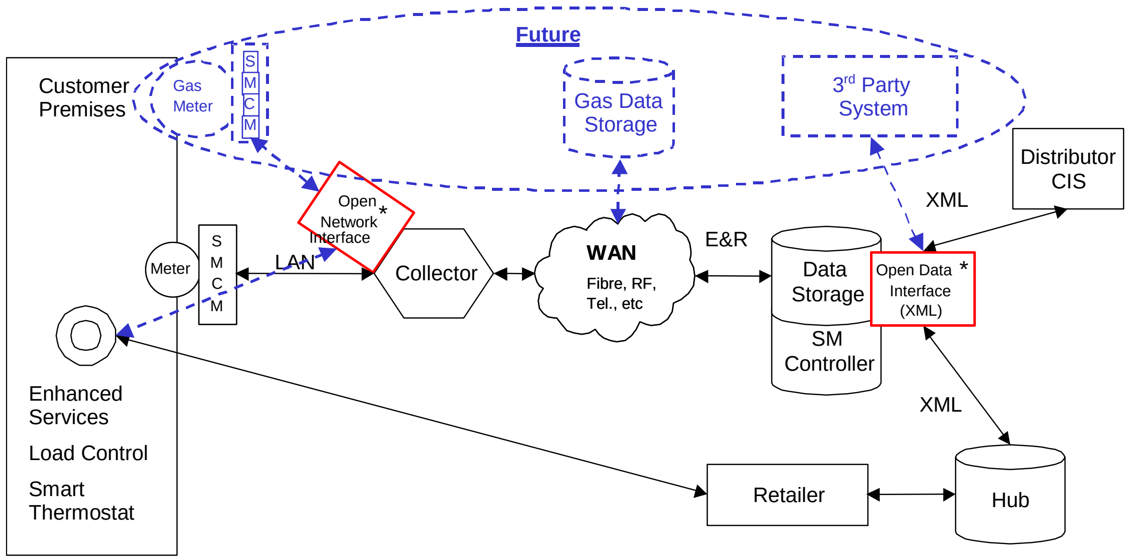
Note: XML standards are imposed by licence condition on distributors or as requirement under the Board's Distribution System Code.



The Board believes that the communications network and meter data storage systems should be available to energy service providers throughout the province of Ontario through open interfaces. Network assets should be accessible via open network interfaces and metering data should be available in XML format. Privacy of customer data is already secured through the Board's codes.

Having an open network interface at the remote end of the last mile, would allow other energy devices, such as gas meters, to connect to the Smart Metering System network infrastructure and send gas data over the Smart Metering System network to a gas data repository. In a similar fashion, having an open data format (XML), would allow other third party applications, such as Web Presentment applications, to access and locally process meter data, (refer to figure 5).

Figure 5: Smart Meter System Future Configuration



The Board is aware that open standards are not widely accepted within the smart meter industry today; however, the Board intends to encourage interconnection and interoperability among various vendors' Smart Meter Systems.

4.3.3 Enabling Load Control

Bi-directional communication will support aggregation of smaller customers for participation in market-based demand response programs. One scenario is for a customer to give load-control ability for specific devices (e.g. air-conditioners, pool pump, or water heater) to a retailer for either a fee or a favourably priced commodity contract. The retailer could control load (to the extent allowed in the agreements with the customers) and could bid the possible load reduction into an IESO-administered market.

In order to do this through the smart meter system, the retailer or service provider needs to be able to send a message for a specific device attached to the system e.g. smart thermostats, real-time displays, various load-controllers, etc. It is therefore important for each device as well as the meter to have a unique, provincial identifier. See Appendix D-3 (*Provincial Addressing*) for information on one option for how this might be accomplished.

It would also be desirable for all the smart meter systems in the province to be able to receive these messages. That way, a load aggregator could send one message to control devices in many different service areas. This could happen either through a central contact or through interconnection of the various systems.

4.3.4 Enhanced Functionality

Vendors may offer systems with functions that go beyond the minimum at competitive prices. Enhanced functions can be built into the system or can be ancillary devices that assist the customer in controlling load. A list of some of these features is provided in Appendix D-4.

4.4 Minimum Smart Metering System Requirements

4.4.1 Minimum Technical Requirements

The Board is proposing the following minimum requirements for smart metering systems.

Key requirements of the system include:

- Systems must meet federal and provincial metering, electric safety, and communications requirements necessary to provide legal measure to the customers within the province of Ontario.

- The system must be capable of two-way communication between the collection computer and the meter communication module at the instigation of either piece of equipment.

- The system must be able to provide hourly consumption data from every meter connected to it without the need to remove the meter or visit the site. Distributors may, at their option, compress hourly data into time-of-use (ToU) and critical peak pricing (CPP) format. However, if compressed data is used, the system must be capable, using the bi-directional communication system, to remotely reconfigure time of use or critical peak pricing registers or to acquire hourly rather than time of use meter data.

- For the first four months after a customer has a smart meter connected to the system, a consumer will receive hourly data after which time the automated meter reading system may be re-configured to "compress" hourly data into time-of-use data if: (1) the system can be so reconfigured remotely, and (2) the OEB mandates a time-of-use rate structure, and (3) the consumer does not require interval data. Requests for interval data after the 4-month period may be available from a distributor but an additional charge may be required for it.

  Compression of data at the meter is possible if the software function exists to perform and confirm success of this reprogramming. Some technologies are capable of hourly data only and compression, if any, would be accomplished at the data collection rather than the meter end of the system. The expectation is that most consumers will not be interested in hourly data after a few months, and for those systems capable of compression at the meter, exercising that option would provide a significant reduction in bandwidth that may be re-deployed for consumers who need it. Compression at the meter is at the option of the distributor.

- The distributor must provide daily feedback to customers on their previous day's energy use. This information must be available in hourly intervals for at least the first four months after the smart meter is installed. Reads after that period may be compressed through reprogramming of the meter over the two-way communication link to transmit the usage by ToU and CPP periods according to the relevant rate schedule. The information on the previous day's use must be available to the customer by 8:00 am each morning. See Appendix D-5.

- Reads acquired by the smart meter data collection computer must be identical to the data retrieved from the meter. Hourly reads must retain the precision of the meter, i.e., 10 Watt hours (.01 kWh) per interval.

- When required, pricing changes for the ToU and CPP registers must occur on the hour with 24 hours advance notice. Reconfiguration of the TOU and CPP registers to comply with changes must be completed 16 hours after notification of the change. For time reference information see Appendix D-6.

- Distributors must choose vendors that have a proven track record in the field. The Board will evaluate distributors' prudence in this regard by considering the due diligence exercised in the following factors, among others:

    - Number of metering systems successfully deployed in other jurisdictions;

    - Reputation of the vendor demonstrated by references from distributors who have deployed its system, site inspections of deployed systems etc.;

    - Financial stability of the vendor/manufacturer;

    - Ability to mass produce and assure quality standards for the requisite number of units;

    - Demonstrated software capability for managing large numbers of end devices;

    - Demonstrated customer support, training and warranty services; and

    - Availability and feedback of product user groups.

- The architecture of each Smart Metering System must include sufficient redundancy to ensure the integrity of data collection and adherence to performance specifications outlined in this document. See Appendix D-7 (*Smart Meter Technology requirements*).

- Ninety-five percent of all reads should be available to customers by 8:00 am the following day. Within a 72-hour period, 99.9% of reads should be available.

- Missing reads must be logged and reported through the system by 6:00 am the following morning. An automated process called Editing and Rebuilding (E&R) will be specified by the OEB and will be implemented to standardize the method for filling in data gaps. See Appendix D-8 for an outline of proposed E&R requirements.

- The system must be able to construct the peak hourly demand for Group 2 customers (general service customers with peak demands between 50 kW and 200 kW). It must collect data time-stamped in the meter or be able to read ToU registers or demand registers in the meter.

- The system must be capable of providing the same level of functionality for the initial implementation as for full-scale deployment in the distributor's service area. Monitoring, management and data collection capabilities of the system must be measured to Smart Metering System specification standards.[7]

- The system must have an open network interface at the remote end of the Local Area Network or the Wide Area Network if the system does not need a LAN.

4.4.2 Data Collection Computer Monitoring and Reporting Capability

The collection computer's main function is to confirm the number of end points that are connected and operating on the system. The database in the computer connects the meter information to the customer's account information in the distributor's customer information system.

The collection computer also monitors the overall health of the system's transmissions and all network operations. Upon completion of the nightly (or more frequent) read transmissions, a number of reports must be generated by the computer that enable the distributor to evaluate how well the system is operating.

There are a number of critical factors that could put at risk the 95% read transmission success rate. These include:

- Network failures;
- Communication link failures;
- Power failures;
- Memory capacity issues;
- Meter failures;
- Problems verifying reconfiguration of time parameters for systems using ToU data; and
- Failure to reprogram the communication module for ToU.

[7] Smart Metering System functionality refers to the ability to meet read and interval requirements and data transmission throughput as specified in the Smart Metering System Functionality Specification and resulting distributors' RFP.

The system must be able to alert the distributor immediately to any of these. Any items of a non-critical nature must be trended, so that any anomalies that could potentially impact the system over time are monitored. These reports, called Non-Critical Smart Metering System Reports, are delivered after the nightly read transmissions.

Minimum Non-Critical Smart Metering System Reporting

- Successful initialization of modules installed in the field;
- Discrepancies in module and CIS links;
- Successful capture of readings – benchmark of 95%;
- Read reports;
- Alarms and status indicators at modules;
- Suspected tamper and trending reports;
- Communication link functionality monitoring; and
- Status indicators for regional collectors.

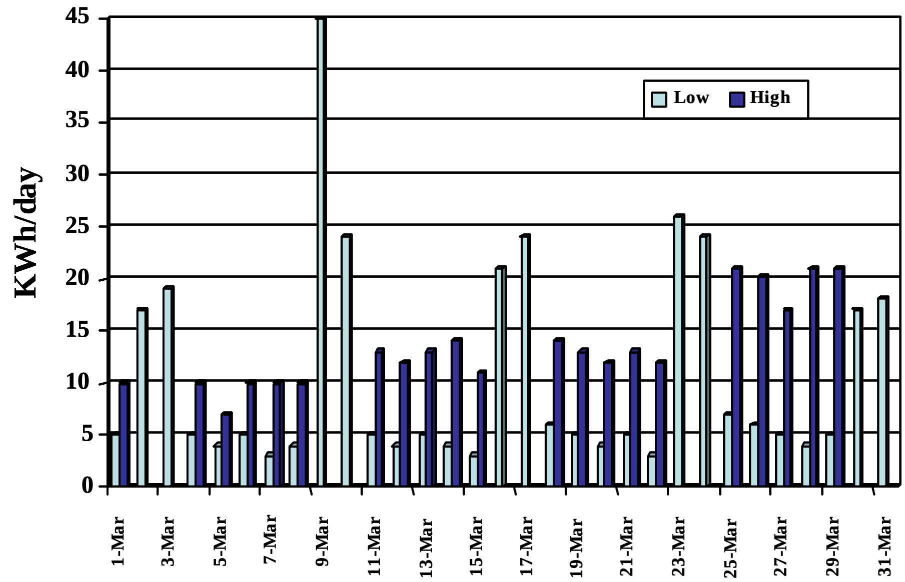
These minimum specifications will need to be included in distributor requests for proposals (RFP) to vendors. For more detailed information of use to distributors in constructing an RFP, see Appendix D-7.

4.5 Customer Information

Customers must have the tools to understand their energy usage and the ability to change their patterns.

The ability to see their consumption by hourly intervals is expected to provide customers with the necessary information. Providing this information in a manner that reflects their usage in specific rate periods is also expected to be of value and importance in assisting the customer to control consumption. See Figure 5.

Figure 6: Sample Customer Monthly ToU Consumption



Pricing for all rate periods in each 24-hour period must be estimated and presented to the customer with the usage information by 8:00 am every day.

For energy usage comparison purposes, 13 months of on-line data must be available to the customer.

The Board must develop standards for bill and Internet data presentation to ensure that customers understand the feedback information.

If the IESO calls a critical peak period because the Province's energy system is expected to be near capacity, the notification must go out no less than 24 hours before the critical period begins. The alert can be sent through television, radio and print to make sure that the most possible people are aware of the critical call, are aware of the price increase and can avoid high bills by reducing consumption. At a minimum, the distributor should add the information to the customer information call centre and web-site. A voluntary e-mail or auto-dial notification list would be even more helpful. The Ministry should investigate ways of using emergency broadcast notifications.

Additional details regarding Minimum Requirements for Customer Information are provided in Appendix D-9.

Distributors should provide daily use information to customers by: automated voice response, customer service support line, Internet and/or e-mail.

For further details on Customer Presentment Options see Appendix D-10.

4.6 Information Detail Parameters To Third Parties

Retailers will have access to the same level of data as their customers. If the retailer needs hourly data for any customer not currently receiving this level of data, the retailer will be obligated to pay the increased cost of collecting this data. Information presented to the customer must be available for downloading by authorized retail energy service entities in standard format.

Section 11.2 of the Retail Settlement Code specifies conditions for the customer or a third party to interrogate a customer's meter. The Board does not anticipate changing this requirement but may update the Code to reflect smart meter systems. Ancillary devices may be required at an additional customer charge.

4.6.1 Standard Format for Data

The Board recommends that retailers receive meter data from distributors the following day. Currently, these data are transferred through the electronic business transaction (EBT) system of hubs. The XML standard format used to support EBT for market opening is expected to be the most viable option for transferring use information to the retailers. The distributors will still have to make the data available in XML standard format. For the data to continue to flow through them, the hubs would need to modify their systems to handle the higher data volume. The Program Coordinator would monitor and test hub readiness during Inter-Party Testing. In the event that hubs were not ready, retailers would be able to make other arrangements to receive the meter data by the next day.

4.6.2 Access to Historical Data

Two years of smart metering data that has been validated and used to calculate and settle a customer's bill should be available online to satisfy the requirements of the Retail Settlement Code. It is recommended that an additional seven years of data be retained off line and the Board notes that Measurement Canada rules may require even longer retention periods than that.

As noted, the customer's previous day's usage information must be available for access by the retailer by 8:00 am the following day. Data that must be edited must be available in rebuilt format within three days.

Appendix D-11 contains information on service bureau options for data management.

4.6.3 Ownership and Operation of the Collection Computer

The Board heard suggestions from data management companies that a centralized data repository and management system would have cost advantages through economies of scale over every distributor establishing its own. This idea may have merit but supporting documentation was lacking and the Board is unable to validate the concept at this stage. Distributors can resolve the question by consulting with suppliers of data centre services prior to making decisions about data management infrastructure. The Board will require an analysis of the centralized repository alternative as part of its prudence review of the large urban distributors' procurement plans and the decision made in that proceeding will inform the Board's guidance to the remaining distributors.

4.7 Distributor Guidelines for RFP Development

The inherent strengths and weaknesses of each smart metering system depend to a large degree on the telecommunications medium used to transmit the data. Diversity in the type of customer base, demographics and telecommunications infrastructure available will require distributors to select systems that are most appropriate, cost effective and available in their service area. Apart from infrastructure availability, the distance between meters is often a key factor in smart metering system selection as it will determine system performance and ultimately the overall cost per point of the entire smart metering system. The information in Appendix D-12, provides more structure, technical information and functionality guidelines on the various vendor smart metering system options available to distributors.

It must be noted that the information contained in Appendix D-12 is a guideline only. Specific smart metering system vendors may have overcome some obstacles noted in that appendix as impediments to achieving the required functionality.

5. Non-Commodity Time of Use Rates

The Minister asked the Board to address the need for and potential effectiveness of non-commodity time of use rate structures as a means to complement the implementation of smart meters and maximize the benefits.

The charge for electrical energy (the commodity) is generally the single largest charge on a consumer's bill. For a typical residential consumer, the commodity charge is, on average, 45% to 50% of the total bill (before GST) depending on the time of year. The commodity portion of a consumer's bill will vary by time of use once the consumer has a smart meter and the Board's regulated price plan for smart meters is in effect.

In addition to the commodity, a consumer's total electricity bill also includes several other charges:[8]

- Delivery (transmission and distribution),
- Regulatory costs (wholesale market service charge and, in some cases, a standard supply service charge), and
- Debt retirement charge (collected by distributors on behalf of Ontario Electricity Financial Corporation).

Each of these three charges fluctuates to some extent today as a consumer's electricity consumption increases or decreases. However, none (except perhaps for delivery charges for large consumers with interval meters) currently varies depending on when during a month a consumer uses energy.

If some or all of these non-commodity charges were levied based on time of use, the financial incentive for a consumer to reduce electricity consumption during peak periods obviously would be increased.

The remainder of this section describes how these non-commodity charges are computed today and comments on the possibility of moving to time-of-use charges in the future.

[8] This classification of non-commodity charges is based on the bill classifications for low-volume consumers that were recently mandated by Ontario Regulation 275/04, "Information on Invoices to Low-Volume Consumers of Electricity." Electricity bills for low-volume consumers now show charges grouped into these categories. Electricity bills for larger consumers may have different groupings and more detail but the nature of the charges is the same as the charges to low-volume consumers.

5.1 Delivery Charges

Distributors bill consumers for delivery based on Board-approved rates to cover both (a) charges from transmitters to distributors for use of the high voltage transmission system, and (b) charges for use of the local lower voltage distribution system. For a typical residential consumer, total delivery charges may be 35% to 40% of the total electricity bill before GST.

5.1.1 Transmission Rates

There are two types of transmission rates to consider. Wholesale rates are those charges to distributors as measured at sophisticated metering delivery points. Retail transmission service rates are those distribution charges to consumers to recover these wholesale costs. For a number of reasons, including the difference in metering technology, retail transmission rates are different from wholesale transmission rates.

All wholesale transmission customers, including distributors, pay for transmission services based on their peak demand in a month.[9] In this respect, at least one of the components of the wholesale transmission rate can be described as time differentiated.

Retail transmission rates were always intended to be pass through charges of wholesale costs. That is, distributors would re-bill their customers, without a profit, for all of the transmission costs the distributor incurred. Because the amount of transmission costs for any month can only be determined after the month ends, distributors bill their customers at fixed rates based on estimated charges and capture any differences in a variance account.[10]

Some customers with interval meters are charged in the same manner as the distributor is charged for transmission at the wholesale level. Distributors bill transmission costs to other customers on two different bases.

- Customers with non-time-of-use demand meters (and some customers with interval meters) are charged based on the customer's peak demand (kW) during a month. This is usually a non-coincident peak demand. It is the customer's peak load in the month and is not necessarily the customer's demand in the hour in which province-wide demand is highest.

[9] Wholesale transmission rates charged to distributors and other transmission customers cover various services (network, connection, and transformation services) and on a per delivery point basis they are computed using either coincident or non-coincident peak demand during the month.

[10] The methodology for setting transmission rates for consumers connected to a distributor's system is set out in Chapter 11 of the Board's *Distribution Rate Handbook*.

- Customers without an interval meter or a non-time-of-use demand meter (e.g., residential and small business consumers) are charged based on total consumption (kWh) during a month.

5.1.2 Distribution Rates

All customers pay a fixed monthly customer charge and a variable distribution charge. The fixed charges vary by distributor. The variable charges are volumetric: demand-metered customers pay based on peak demand (kW) and all other customers are charged based on energy consumption (kWh).

The Board has initiated a project to review the revenue requirements of distributors in order to set new rates to be effective in May 2006. That project does not include a fundamental re-examination of the design of distribution rates.

5.1.3 Preliminary Assessment

A primary principle of cost allocation is cost causality. This principle stipulates that in a pragmatic fashion costs should be recovered from the customer who causes the costs. The unbundling of energy costs from delivery costs significantly alters a ratemaking argument for delivery rates that are time-of-use rates. This is because distribution and transmission networks are built to meet long-run peak demands. The cost causation principle, and therefore the pricing signal, in delivery rates reflect the needs of infrastructure and not supply.

This does not make time-of-use delivery charges inappropriate, but it does make them harder to design. Transmission rates currently have a time-of-use structure through the peak demand rate structures applicable to larger customers that have interval meters or non-time-of-use demand meters. If those customers reduce their peak demand through load shifting, they pay lower delivery fees.

Delivery rates can be modified with an objective of reducing load or shifting load or they could be designed to encourage reducing load. For example, wholesale transmission rates can be designed to affect the substitution of generation and transmission.

Although the Board believes the issue should be examined, it is also mindful of several conceptual and practical issues that would have to be resolved before time-of-use transmission and distribution rates could be designed and implemented. These include:

- A distributor’s costs are largely fixed (at least in the short- and medium-term) because of the capital investment in wires, poles, transformers and other equipment. Compared to time-of-use rates for the commodity, it is much less certain that time-of-use rate structures for distribution services would incent consumer behaviour that has a positive impact on overall system costs.[11] This fact must be carefully considered in designing time-of-use rate structures for distribution services. A poorly designed time-of-use structure could have the effect of simply re-allocating an unequal, and arguably unfair, burden of delivery costs among consumers.

- Current rates reflect a given load diversity. Altering delivery charges to reflect time-of-use could potentially alter load diversity. Since wholesale transmission rates are calculated on a delivery point basis it is theoretically possible to create time-of-use rates that alter local peaks and create incremental and unnecessary infrastructure costs.

- With respect to transmission charges to a distributor's customers, any time-of-use rates would probably have to be linked directly to the rates charged by the transmitters themselves. If that did not occur, there might be a disjoint between what distributors pay and what they collect from consumers. Whether such a straight pass through could be accomplished or whether deferral accounts would still be necessary requires study.

- There are already several, often complex, distribution rate issues that the Board will be addressing over the next few years. Those issues stem from the way that distribution rates were initially set in 1999 and 2000 and from the rate freeze imposed by Bill 210. It is highly unlikely that designing a time-of-use rate structure can proceed as an initiative separate from the resolution of these other issues. The Board is addressing some of those issues in its project on 2006 distributor revenue requirements. Other issues will be addressed in Board projects that will affect distribution rates in 2007 and later years.

5.2 Regulatory Charges

Under the new bill format introduced recently for low-volume consumers, regulatory charges comprise (a) a wholesale market service charge, which is currently fixed at $0.0062 per kWh for all consumers connected to a distributor's system, and (b) a $0.25 per month service fee charged by distributors to standard supply service customers for administration of the pricing plan.

5.2.1 Wholesale market service charge

The wholesale market service charge covers primarily various costs incurred in the wholesale electricity markets administered by the Independent Electricity Market

[11] Time-of-use rates for the commodity give consumers a financial incentive to reduce their demand in those periods when province-wide demand for electricity is high and the IESO is dispatching generation plants that have high fuel and operating costs. Significant aggregate demand response can lead to less reliance on expensive peaking plants and a reduction in overall system cost of generation. That same reduction in demand is unlikely to have any material impact on the short- or medium-term costs of distribution and transmission services.

Operator (IESO). It also includes a $0.001 per kWh charge that supports rate protection for rural and remote consumers.

There are several charges incurred in the IESO-administered wholesale electricity markets that are not captured in the hourly price of energy and that must be recovered by the IESO. There are three categories of such costs:

- Costs that vary hourly (for services rendered by the IESO on behalf of the market participants for operating reserve, congestion management, transmission line losses, and inter-tie offer guarantees in respect of imports of power),

- Costs that vary monthly (principally payments under contracts for ancillary services), and

- The annual operating costs of the IESO (staff, premises, systems).

Collectively, these costs are referred to as IESO-administered "uplift." The hourly uplift is the single largest component of the IESO-administered uplift charge. In the first year of the wholesale market (May 2002 to April 2003), hourly uplift totalled $760 million. A large portion of that amount was incurred in three months during the summer of 2002 when there was abnormally warm weather and energy demand was very high. In the second year of the wholesale market (May 2003 to April 2004), aggregate hourly uplift dropped to $360 million.[12]

When wholesale and retail electricity markets opened in May 2002, the IESO started charging uplift to all wholesale customers, including distributors. The Board authorized distributors to charge their customers $0.0062 per kWh (to cover IESO costs and rural rate assistance) and to accumulate any difference between actual charges and the $0.0062 per kWh collected from consumers in variance accounts that would be cleared periodically.

By November 2002, the amount paid by distributors to the IESO greatly exceeded the amounts actually collected from distribution customers, due to much higher than expected hourly uplift payments. The balance in distributors' variance accounts was well over $100 million. Since November 2002, the amount that distributors pay to the IESO for uplift and rural rate assistance has been frozen at $0.0062 per kWh, the same amount as distributors charge their customers.[13] Since that time, differences between actual IESO-administered uplift in any month and the amounts collected by distributors are now charged or credited to Ontario Electricity Financial Corporation (OEFC).

[12] See *Monitoring Report on the IMO-Administered Electricity Markets for the Period from November 2003 to April 2004*, IESO Market Surveillance Panel, page 17.

[13] Ontario Regulation 436/02, "Payments re Various Electricity-Related Charges."

5.2.2 Preliminary Assessment

The IESO-administered uplift incurred hourly is likely highly correlated with the wholesale energy price in that hour. The other underlying components of the wholesale market costs (rural rate assistance, standard service supply administration fee, and IESO non-hourly uplift) do not vary with time of use and, like distribution costs, there is no clear rate making principle which supports this form of rate design in their recovery. Addressing this issue could result in separating the current wholesale market service rates into its time-differentiated and "fixed" components. This in turns adds potentially unwanted complexity to the collection of wholesale market costs.

The Board would have to address several practical implementation issues were it to design a time-of-use rate structure for IESO hourly uplift. For example, would the time-of-use rate periods be each hour, or would they correspond to the time periods used in the Board's regulated price plan for the commodity? Would deferral accounts be necessary, and which entity would be responsible for the deferral accounts?

5.3 Debt Retirement Charge

Distributors are required to collect this charge from almost all consumers. It is set by regulation at $0.007 per kWh for most Ontario consumers and is paid to OEFC. The amount of this charge is completely independent of when the consumer uses electricity during a month. Unless the regulation were amended to incorporate a time-use charge, there is no basis for requiring distributors to bill customers on a time-of-use basis.

5.4 Billing Customers

If these non-commodity services were charged to customers on a time-of-use basis, customers would need to see and understand how their behaviour has affected their bills. For low-volume customers, Ontario Regulation 275/04 currently prescribes the items to be shown on the bill. It may be necessary to reconsider the content and format of bills for low-volume customers to make these rates effective.

6. Next Steps

The smart meter initiative is both challenging and complex. Everyone involved will need to make coordinated and committed efforts to meet the timelines and the minimum system requirements specified by government policy.

The implementation plan has a detailed implementation timeline identifying important tasks and milestones for project implementation over the next three years. There are several critical tasks in the first year to establish the framework for the implementation:

1. Ministerial approval of the plan.
2. The Program Coordinator must be identified and processes must be set up for provincial coordination and inter-party testing, tracking, exception approval and facilitation.
3. The Board must establish the right regulatory framework. This includes amending the Distribution System Code, the Retail Settlement Code, and the Distribution Rate Handbook. The data editing and rebuilding process must be developed. Deferral accounts must be established for spending in 2005. Provision must be made in 2006 electricity distribution rates applications for smart metering system costs. Implementation targets for 2007 and 2010 will need to be incorporated in the codes. The Regulated Price Plan will establish time-dependent pricing and a timeline for implementation.
4. Vendors wishing to introduce new smart products to the Ontario market should complete the Measurement Canada approval process and acquire the appropriate permissions for any radio frequency licences required by their products.
5. Distributors may undertake technology pilots to assure themselves as to the changes necessary in their own systems. These necessarily will be of rapid deployment and short duration. The large urban distributors must also begin to develop their business processes around procurement, internal schedules and deployment.
6. Government, regulatory bodies and distributors must coordinate for a comprehensive customer communication strategy on the time-dependent nature of electricity commodity prices, the benefits of smart metering systems, the implementation plan and specific distributor approaches.