**Ontario Energy Board**

# Smart Meter
# Implementation Plan

# Draft Report of the Board
# For Comment

**November 9, 2004**

# 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 allow customers to manage their demand for electricity to make 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 draft implementation plan, the Board has consulted with stakeholders through two 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. The Board has benefited greatly from this input and has considered it carefully in developing this plan.

The Board now seeks input from interested stakeholders and the broader public on the draft implementation plan outlined in this document. The Board will then prepare a final plan to submit to the Minister for consideration.

The smart meter initiative is both challenging and complex. Implementation will require the coordinated and committed efforts of many parties over several years. In developing the draft 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 – as well as many detailed implementation issues. In making recommendations, the Board considered many factors, including the structure of the electricity distribution system in Ontario, the need to begin implementation promptly to meet the government's target installation dates, and the estimated overall cost of the proposed system. The more significant issues covered in the draft 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 draft plan does not mandate a specific system or a particular vendor. The type of system that is best for any distribution territory depends on many factors, particularly customer density and geographic factors. Each electricity distributor will have to determine what works best in its territory, 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 must select systems from vendors with at least 10,000 meter points in operation in a smart meter system.

The basic smart meter system proposed by the Board is based on one-way communication (data transferred from the meter to the distributor). The Board considered requiring two-way communication (signals can be sent to and from the meter) but concluded that it eliminated viable systems from contention and could compromise competitive bidding. Also, the basic system proposed by the Board does not include all technical features currently available from vendors. Distributors will be permitted to select smart meter systems that have enhanced functions, such as voltage monitoring, earlier payment, load limiting and remote cut-off. Inclusion of the cost of such enhancements in distribution rates will depend on a business case acceptable to the Board.

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.

## Rollout of smart meters

The draft plan proposes that all new and existing distribution customers in Ontario, including all residential and small commercial customers, have some type of smart meters. 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.

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 installed by many industrial customers. Starting in 2006, once a distributor has selected its smart meter system, 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. In addition to these priority installations, about 12% of the existing meters in the province will need to be changed to smart meters by December 31, 2007 to meet the government’s target.

The Board is encouraging distributors to carry out pilot programs 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.

## Responsibility for implementation

Three parties will have key roles in the implementation process.

### *Distributors*

Distributors will be responsible for choosing the type of 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 territory, 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.

### *Implementation Coordinator*

A single entity will be required to manage the implementation process, to monitor progress, and to coordinate the activities of distributors over several years. One of the responsibilities of this entity would be to review and approve the procurement plans of the distributor buying groups. One option that the Minister could consider is to have the Ontario Power Authority fulfill this role should Bill 100 be passed by the Legislature.

### *Ontario Energy Board*

The Board will be responsible for setting up a regulatory framework for smart meters. That work will include: building smart meter costs into distribution rates; amending OEB codes governing metering and the activities of distributors; amending distributor license conditions; and, where appropriate, setting province-wide standards for distributor business processes, such as data presentment to customers.

## Impact on customers

When a smart meter is installed, two things will change for electricity customers. They will receive timely information on consumption and the pricing plans offered by distributors 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. 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 this new plan 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. 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 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 day before a critical pricing day, customers will 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. Because 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. Once these customers receive smart meters, they will pay the hourly price on their actual hourly consumption.

## Cost

The draft 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 territory, the impact on customer bills will be small initially. It will rise as the implementation program progresses. 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 by 2010 (when full implementation is complete) may be between $3 and $4 a month to cover capital costs and net operating costs. The total capital cost through to 2010 for the proposed system (meter, communications, installation and distributor system changes) is estimated at $1.07 billion. The net increase in annual operating cost for the province is estimated to be $50 million.

The cost estimates in the preceding paragraph, and in the draft 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.

## Comments

Nine (9) copies of written comments on this draft implementation plan should be sent by November 26, 2004, referring to RP-2004-0196, to:

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Board Secretary
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And an electronic copy in PDF format to:
BoardSec@oeb.gov.on.ca

Individuals may file a single copy of their comments.

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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 is to develop the most effective and workable plan to achieve the government policy objective on smart meters and conservation. The Board has tried to balance costs and benefits and to be fair to ratepayers, distributors and competitive companies. By setting reasonable 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 making its recommendations, the Board took into account the technologies commercially available in the market to fulfill a specification that ensures competitive bidding, and the speed of implementation required to meet the Government's targets.

In developing the plan, the Board has seen evidence that providing smart metering systems for all Ontario customers is technically feasible. The time frame is challenging and all involved will have to commit to meeting the deadlines.

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

- automate the reading of meters in 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 the true cost of electricity at daily and seasonal peak demand is significantly higher than at other times. Smart meters measure how much energy a customer uses, and when. Smart meters will give customers a means of controlling their bill through controlling how and when they use electricity. 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 draft 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.

The Board also commissioned a survey of current meter inventories and practices of local electricity distribution companies in Ontario. The preliminary data from that study have helped with overall estimates of costs, benefits and targets. Consolidated information from that survey is expected in time for the final plan.

**This Draft Implementation Plan is being released to interested stakeholders, the industry and the general public for comment. Written comments are to be provided to the Board by November 26, 2004. The Board will consider these comments in revising the Plan for the Minister by February 15, 2005.**

## 1.4 Structure of the Draft Implementation Plan

This section of the document describes the project. 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 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.

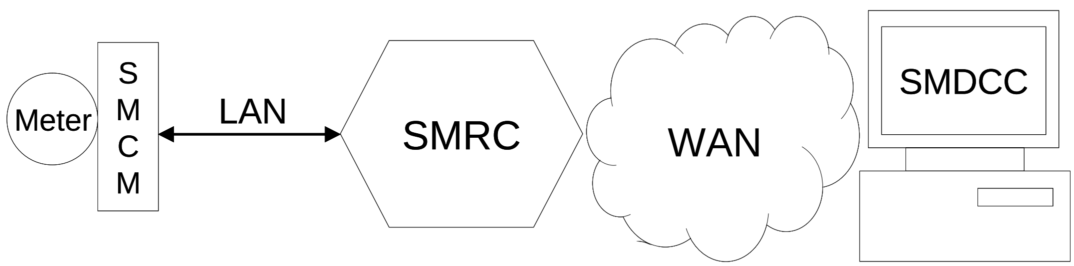
The appendices include a glossary of terms and acronyms, background information and further details of the draft plan.

## 1.5 Definition of Smart Meter Terms and System Components

The diagram and definitions in this section describe a smart metering system (SMS).

**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 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 SMCM 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 Smart Metering System (SMS) to the SM Data Collection Computer (SMDCC). The SMCM may not have memory in the meter or in the SMCM. Information that is not stored in resident SMCM 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 SM Data Collection Computer.

### 1.5.3 Local Area Network (LAN)

The LAN is 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 meter data over long distances, traditionally greater than 1.5 km. WANs transmit via fiber, telephone, and radio frequency over a utility-owned private network or a publicly-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 SMDCC is also the central control point for registering new modules and accepting their data. 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 communication module adds, moves, changes and programming of new time periods in the meters, if 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, a provincial implementation coordinator, retailers, 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 draft 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.

## 2.2 Implementation Roles and Responsibilities

### 2.2.1 Local Distribution Companies

This report recommends that distributors continue to be responsible for metering service. This means that, distributors would be tasked with all aspects of implementation within their areas, including procurement, logistics, resourcing, deployment and communication. The Board recommends that distributors organize themselves into distributor buying groups for procurement and other aspects of the implementation where appropriate. They would need to develop procurement plans and business cases and submit them for review by the implementation coordinator. They would have to support large customer requests for early scheduling of meter installations and additional functionality in a timely manner. They would report their progress to the implementation coordinator.

The Board analyzed a number of alternatives. 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 sufficient 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 considered was for a new regulated entity to take over all of the metering, meter reading and data management in the province and hand off data to the distributor. This model could realize economies of scale and allow more efficient utilization of the proposed smart metering investment. From an implementation timeline perspective, this option would require that a new regulated entity be set up and that Measurement Canada policies such as LMB-EG01 be changed in order to eliminate the distributor's legal responsibility for metering. With the already tight timelines imposed by the provincial targets, the Board felt that this would delay a much-needed early start to the initiative.

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

### 2.2.2 Ontario Energy Board

The Board's role in implementation is to 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 should start these activities in January 2005.

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

### 2.2.3 Implementation Coordinator

The implementation coordinator would ensure the progress needed to meet provincial targets, as well as an appropriate level of uniformity in technology. It would oversee procurement processes submitted by distributor buying groups. Distributors would provide updates on their progress and costs on a quarterly basis to the OEB and the implementation coordinator. In the event of distributor non-compliance, the implementation 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.

The Board feels that there is an inherent conflict were it to take on many of the functions of the implementation coordinator, given its later authority for rates. One option that the Minister could consider is to have the Ontario Power Authority fulfill this role should Bill 100 be passed by the Legislature. For other options considered for provincial coordination, see Appendix B-2 (*Provincial Coordination and Distributor Compliance*).

## 2.3 Implementation Timeline

Figure 2 provides an overall timeline to meet the December 2007 provincial target of 800,000 customers with smart metering. The chart is broken into workstreams for the OEB, the implementation coordinator and distributors. These are:

**Ontario Energy Board:**

- **Consultation** includes the completion of the consultation process by obtaining feedback on the draft implementation plan from interested stakeholders and the broader public, finalizing the report and submitting it to the Minister of Energy for approval by February 15, 2005.

- **Regulatory** includes amending rules, codes and standards, including any notice and comment periods required. 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. These are to be completed by mid-2005.

- **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 communication standards. These are to be completed by mid-2005.

**Implementation Coordinator:**

- **Provincial Coordination and Project Management** involves appointing an implementation coordinator, setting up a steering committee, developing required business processes and systems for the implementation coordinator, overseeing distributor and EBT implementation progress, and resolving issues that hinder progress. It would require legislative change for the implementation coordinator to have binding authority over distributors. These activities continue through the life of the project. The implementation coordinator should be named in the first quarter of 2005.

- **Communication** includes developing a detailed communication plan involving both pro-active and reactive communication. The execution of the plan would involve coordinating Ministry of Energy, implementation coordinator, Board, and distributor communication efforts. These activities should begin in the second quarter of 2005.

- **Inter-Party Testing** is necessary to ensure that key players are ready. The testing will be made up of two stages: scenario testing followed by operational testing. Testing would take place in mid-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 telephone communications. This would begin in 2005.

**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. Choosing technology should begin in the first quarter of 2005.

- **Procurement** combines distributors into buying groups with common needs, runs RFP processes to obtain costs for required technology, develops and submits business cases (for functionality beyond the minimum requirements) and submits procurement plans to the implementation coordinator for approval, negotiates with and awards contracts to vendors, and organizes logistics. This should begin by mid-2005.

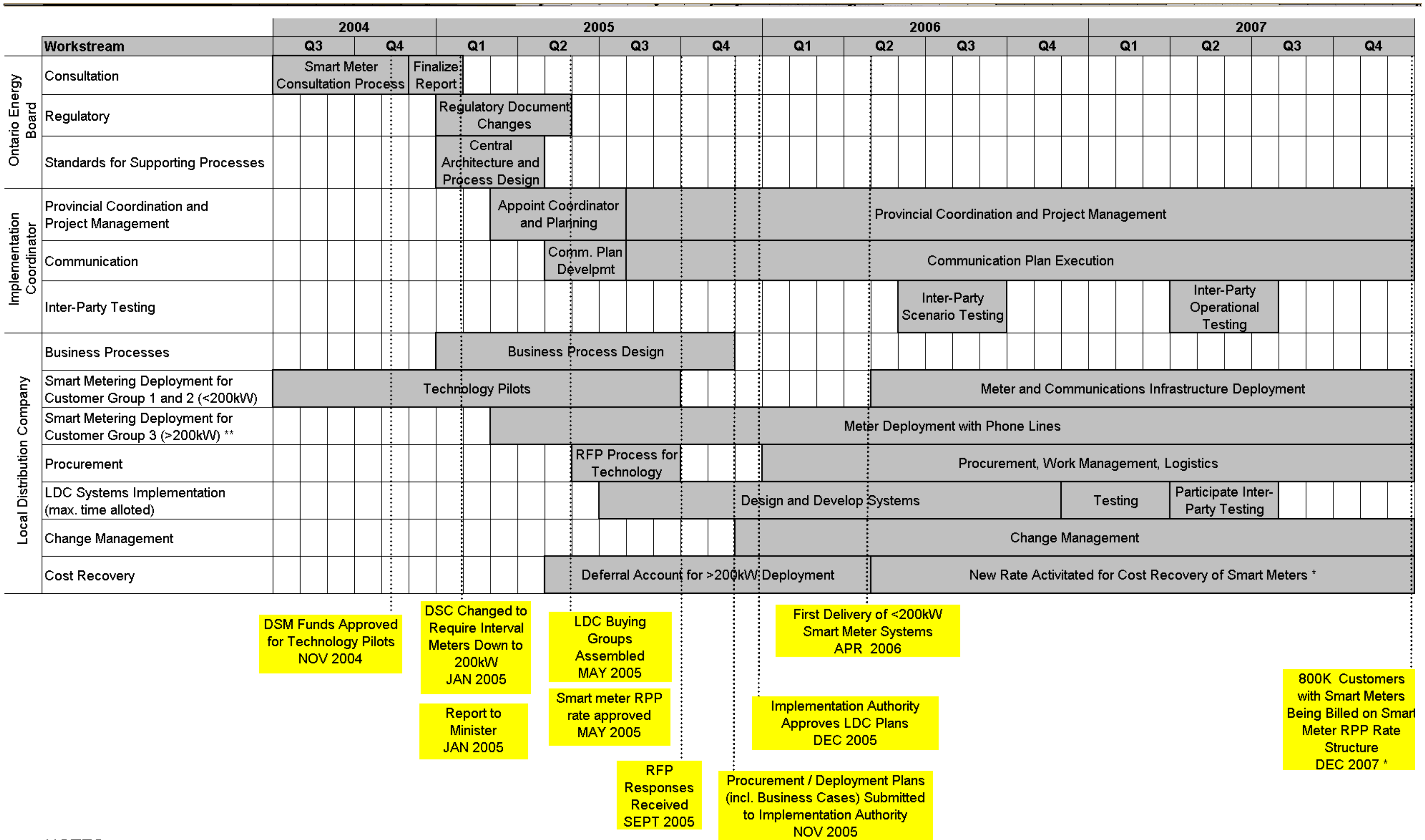
**Distributor Systems Implementation** includes implementing systems to support the smart metering technology, testing systems and participating in inter-party testing coordinated by the implementation coordinator. This should begin by mid-2005. Although Figure 2 shows this activity continuing through 2007, the Board expects that many distributors would be able to conclude much earlier.

**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 in the second quarter of 2005.

**Cost Recovery** includes reviewing cost recovery processes from the Board, submitting and obtaining approval on rate applications, and implementing new rates that allow for the recovery of 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




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. Four to six buying groups across the province should maximize the savings in each group from economies of scale. Buying groups are encouraged to conduct more than one contract over the life of this initiative to ensure that emerging technologies are considered in later years. The Niagara Erie Public Power Alliance Group, Cornerstone Hydro Electric Concepts Association Group and the Upper Canada Energy Alliance, three examples of groups, together account for more than one-third of the distributors in the province. The implementation coordinator would facilitate the creation of buying groups. The buying groups should be non-discriminatory and open to any distributor. It would be inappropriate to have any particular buying group gain exclusive right to a technology.

Forming these buying groups as part of this initiative may also encourage distributors to pursue efficiencies 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.

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 implementation 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. It would hinder early adopters among distributors who are anxious to get started on their deployment since they would have to wait for the provincial process.

**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, an issue 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**

The option for a unique solution, where 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. Many meter manufacturers did not feel that the size of the market justified 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

The Board recognizes that there may be concern over the voluntary buying groups needing enough of any single product to get economies of scale. This level is generally between 50,000 and 100,000 units. The implementation coordinator 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. The implementation coordinator would develop guidelines on preparing plans. Buying groups would submit their procurement process for customers less than 200kW to the implementation coordinator. The implementation coordinator would assess the distributors' efforts to form buying groups and capture economies of scale. It is recommended that plans would need to be submitted no later than November 2005. Distributors would follow their current process for buying interval meters for customers greater than 200kW and would not require approval.

The Minister will have to determine whether the oversight role should be one of facilitator and information resource or of an approval authority. Legislative change would be needed for the implementation coordinator to have binding authority over the distributors.

The Board could use the implementation coordinator's assessment as a part of a later prudence review for setting rates.

### 2.4.3 Business Cases for Enhanced Functionality

Where a distributor intended to provide functions that went beyond the minimum standards described in Section 4.4 of this document, and required cost recovery, 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. For example, a distributor with a large student population in rental units may have frequent transfer of accounts and a large number of special reads. This distributor may be able to cost justify remote disconnect/reconnect.

## 2.5 Deployment

### 2.5.1 Distributor Early Adopters Conduct Technology Pilots

Failed technology is one of the greatest risks to the smart metering initiative. The Board will encourage distributors to conduct pilots of a variety of vendor technologies with the testing to be completed by November 2005. Early adopters who conduct the pilots will ensure timely identification of technology issues and prevent issues from arising after more distributors start mass deployment. The implementation coordinator should share the results of the pilots to educate all distributors.

### 2.5.2 Deployment Work Programs

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.

**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<br>>50kW customers and other three-phase metering | A | Certified meter technician | One off installations | Approx. 50,000 |
| Group 1<br>Residential and GS <50kW with single phase metering | B | Installers with task specific training only | Mass deployment (distributor area sweep) | Approx. 4.3 million |

### 2.5.3 Priorities in Meter Deployment

There is no strong evidence that any one Ontario customer group is a better focus for consumption shifting than another. U.S. studies may not necessarily apply to Ontario. As well, customer response to load shifting depends heavily on commodity price plans, distribution rate structures and effective DSM programs.

Certain priorities, however, suggest themselves. Putting smart meters in new installations minimizes stranded costs. Early adopters -- general service customers who request installation -- likely have load to shift and will produce early benefits. Publicly funded buildings are often referred to as the MUSH sector: municipal buildings, universities, schools and hospitals. They receive funding from tax budgets and increased energy costs mean decreased spending in other areas.

Below are the rankings for various customer groups that reflect these considerations. Small commercial and residential customers with three-phase meters 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 that lack the communication link for next day feedback.

**Table C: Work Program A**

| Priority | Group | Number of Meters |
|---|---|---|
| 1 | New installations, service upgrades and meter changeouts | Approximately 50,000 |
| 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. Within the second group, the distributor is likely to do a street or neighbourhood at once.

**Table D: Work Program B**

| Priority | Group | Number of Meters |
|---|---|---|
| 1 | New installations, service upgrades and meter changeouts | Approximately 170,000 /year |
| 2 | Residential and GS < 50kW (single phase) | Approximately 4,300,000 |

For distributor meter statistics and estimates, details on rationale for distributor priorities and mass deployment suggestions, see Appendix B-5 (*Deployment Priorities and Individual Distributor Targets*).

### 2.5.4 Distributor Targets

To meet the provincial targets, all distributors will need 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 implementation coordinator (Work Program A)

- Deployment of 100% of new installations, meter changeouts and upgrades on an annual basis starting after the approval of procurement plans by the implementation coordinator (Work Program A and B)
- Deployment of 12% of remaining meters (Work Program B)
- Completion of all support systems including data management system, CIS modifications, meter reading system and new interfaces into the EBT hubs.

It should be noted that 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.

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.

#### 2.5.5 Deployment in Congested Zones

Every year, the IMO publishes an integrated assessment of the security and adequacy of the Ontario electricity system over the next 10 years. Currently the IMO has identified three congested zones (Toronto, western GTA and northern GTA). The IMO has suggested demand reduction initiatives should target these areas. The Board's draft plan addresses congestion zones with the following two recommendations:

- New installations should be the highest priority. Since high growth areas tend also to be congested areas, putting smart meters on all new installations will ensure that a greater proportion of meters will be deployed in high growth and, hence, high congestion areas.
- Distributors serving congested areas should deploy Work Program B meters in those areas first.

#### 2.5.6 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 implementation coordinator 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.

This report recommends that 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.

### 2.5.7 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.

Existing Prepaid Meters

There are about 2,000 prepaid meters in the province that do not meet the minimum requirements of a smart meter. 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). If these grandfathered meters need to be replaced, the meter should be replaced with a 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.

### 2.5.8 Distributor Specific Mass Deployment Strategies

Distributors may present alternative 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. Examples of alternate plans include:

- Developing a "multi-meter" application, combining electric and/or water and gas installations to develop common communication platforms;
- Developing a WAN network that takes advantage of local opportunities such as fibre, unused radio bandwidth, phone line, cable or power-line carrier;
- Combining with other work management opportunities, work programs or conservation and demand management initiatives.

## 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.

## Figure 3: Deployment Targets

| | Customers | | | | Priority Groups for 2007 Provincial Target | | | |
|---|---|---|---|---|---|---|---|---|
| **LDC Name** | **Res. Cust.** | **Comm. Cust.** | **Ind. Cust.** | **Total Cust.** | **GS >50kW** | **New Installs / Service Upgrades (per year)** | **Meter Changeouts (per year)** | **<50kW and residential** |
| TOTAL | 3,921,528 | 426,583 | 10,623 | 4,359,412 | 49,937 | 99,705 | 76,297 | 4,309,475 |

| Assumptions | | | | |
|---|---|---|---|---|
| Deployment % - 2005 | 20% | 0% | 0% | 0% |
| Deployment % - 2006 | 80% | 75% | 75% | 4% |
| Deployment % - 2007 | 0% | 100% | 100% | 8% |
| Deployment % - 2008 | 0% | 100% | 100% | 20% |
| Deployment % - 2009 | 0% | 100% | 100% | 28% |
| Deployment % - 2010 | 0% | 100% | 100% | 40% |

**Deployment Timeline**

| Customer Groups | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | TOTAL |
|---|---|---|---|---|---|---|---|
| GS >50kW | 9,987 | 39,950 | 0 | 0 | 0 | 0 | 49,937 |
| New Installs / Service Upgrades | 0 | 71,040 | 94,720 | 99,705 | 99,705 | 111,388 | 547,597 |
| Meter Changeouts | 0 | 54,362 | 72,482 | 76,297 | 76,297 | 76,297 | 419,633 |
| GS <50kW and residential | 0 | 172,379 | 344,758 | 861,895 | 1,206,653 | 1,723,790 | 4,309,475 |
| **Total** | **9,987** | **337,730** | **511,960** | **1,037,897** | **1,382,655** | **1,911,475** | **5,191,704** |
| **Cummulative Total** | **9,987** | **347,717** | **859,677** | **1,897,574** | **3,280,229** | **5,191,704** | |
| **Provincial Target** | | | **800,000** | | | **All** | |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Monthly install rate** | 1,665 | 28,144 | 42,663 | 86,491 | 115,221 | 159,290 |

### 2.6.2 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. The communication method used for Group 3 customers is likely to be dedicated or shared phone lines. 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 asked for enhanced functionality or requested off-hours installation, there might be an additional charge.

### 2.6.3 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

An assessment looked at the potential barriers to the smart metering initiative. Appendix B-6 (*Potential Barriers and Mitigation Plans*) contains the full assessment. 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. The implementation coordinator should execute a careful and properly orchestrated communication and education plan that is consistent with messages at the local levels. Customers must be shown how using the new smart metering technology can save them money. Distributors should coordinate visits to customers' homes (e.g. to install meters) to minimize disruption to customers and better use distributor resources. 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.

To realize all potential benefit, this initiative requires a strong communications strategy. It must explain how customers will save money and the province achieve greater conservation through smart metering.

The communications plan could include some of the following options:

- Ministerial announcement
- Mass communications
- Bill stuffer
- Distributor targeted communications
- Communication around the installations
- Six month follow-up
- Place holder for Regulated Price Plan
- Large customers communications

The implementation coordinator should also monitor stakeholder concerns about the smart meter program and communicate as needed.

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 the implementation coordinator be set up as soon as possible and its first priority be to communicate required decision dates and the impact of missing deadlines.

In addition, the implementation coordinator should chair a steering committee of stakeholders to ensure that issues among agencies are resolved in a timely manner. Representatives of distributors, the Board, the Ontario Power Authority (which may have the role of implementation coordinator), the Canadian Radio-television and Telecommunications Commission, EBT Hub, the Electrical Safety Authority, Measurement Canada, the IMO 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 plans to the implementation coordinator for approval will provide distributors with some assurance that they are following an approved process and will reduce the financial risk of cost recovery. As well, the implementation coordinator will be setting interim milestones for distributors and will use the tools at its disposal to support distributors who need help meeting timelines. As noted, all distributors should be in a buying group and the groups must be large enough to ensure economies of scale. The Board and the implementation coordinator will have to be clear about the criteria for distributor buying groups.

## 2.8 Distributor Impacts

To help distributors understand the impact of this initiative on their business, Appendix B-7 (*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 estimated capital cost of installing smart meters for all customers is estimated at $1.07 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 by 2010 (when full implementation is complete) may be between $3 and $4 a month to cover capital costs and net operating costs. 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.
- **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 IMO 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.

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 demand. Uplift charges for congestion management and reserve capacity are also lower for all customers when the system peak is lower.

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.

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

### 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, 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.

[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.

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 benefits of smart metering have this investment requirement to realize them. 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*).

## 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.

Small single-phase commercial customers 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 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. All electromechanical meters will be rendered obsolete by smart meters. Some distributors have deployed electronic versions of these meters, but their population is relatively small. Some electronic meters might be adaptable to smart metering systems.

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] This figure is not an appropriate measure of costs that will be stranded because some assets will continue to be used and depreciate normally through 2010.[5]

There is a limited potential to reuse this hardware. Residential meters are worth only about $20 on average on distributor books and the cost to prepare and ship them elsewhere might exceed that, while new meters of this type cost about $40. The Ontario meters are also equipped with a test dial, a requirement unique to Canada that might make them less attractive to foreign jurisdictions.

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

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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.

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.

## 3.4 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 and related to benefits;
- Recovery should promote economic efficiency, 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 options are discussed in detail below.

For either option, 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 enjoy benefits equally or if those with higher use get greater benefits.

### 3.4.1 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 incremental rates, the budget and the progress toward targets to adjust the revenue requirement 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.

### 3.4.2 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 all customers will ultimately benefit. Distributors would have to either attribute a significant portion of shared costs to fixed-price customers or defer that portion of costs until the customers are using them. 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 of cost causality. That is, 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 as described in section 3.2.1.

### 3.4.3 Recovery of Costs for Customers over 200 kW

Currently the Distribution System Code requires that customers with interval meters pay the incremental cost of the installation. All existing customers over 1000 kW and many customers over 500 kW or less have paid for their meters. The Board will decide as part of its amendment of the DSC whether or not to continue to require customer contribution for interval meters. If not, distributors would have to have a deferral account for spending that takes place in 2005, before 2006 rates can be changed.

### 3.4.4 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.

### 3.4.5 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 undepreciated 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 needed to apply current and potential rate charges and commodity prices. The data needed drive the base level requirements for the smart meter system. The following chart determine 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: Customer billing and data requirements**

| Customer Group No. | Customer Segment | Billing quantities | Meter Data Collection Requirements | SMS 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 in-meter time stamp | 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. 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.

There are a few customers who do not fit into these three categories. 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 & 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.

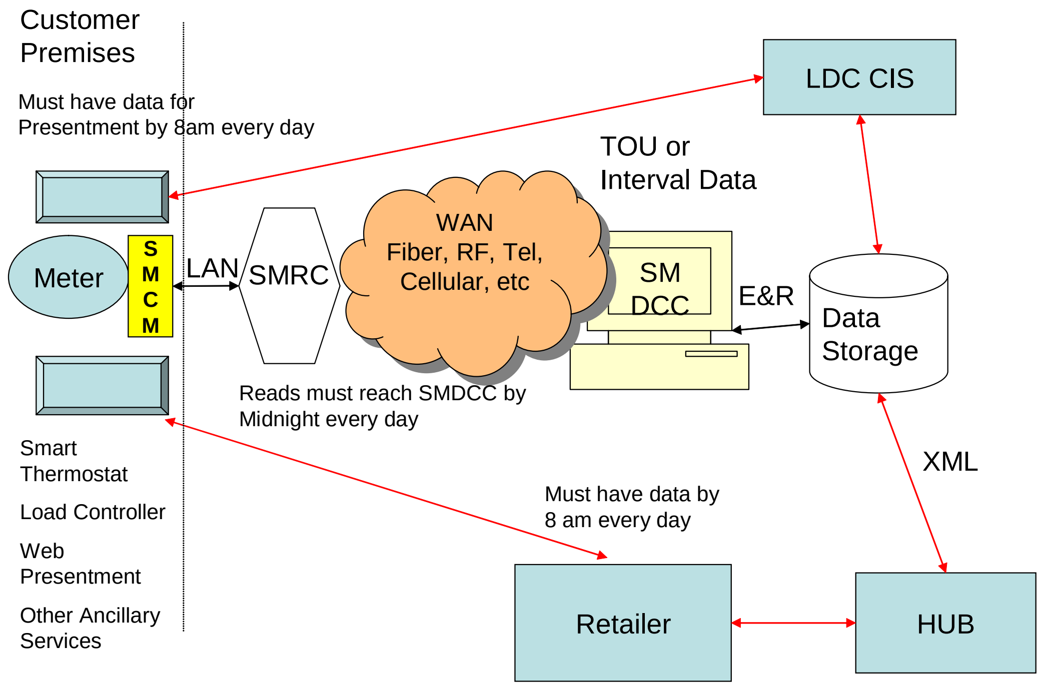
There may not be enough currently approved products to guarantee competitive bidding for all customer densities. The approval process can take between six months and two years depending on the level of innovation of the product. Vendors should seek approval as soon as possible if they expect to serve this market.

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.

## 4.3 Required SMS Service and Information Flow

Figure 4 shows what happens after the meter usage information arrives at the data collection computer. The meter data must be edited and rebuilt and moved to the data storage/warehousing. The distributor can upload the actual billing reads from data storage into its customer information system. Importing only the billing reads would involve fewer upgrades to existing customer information systems. The data storage facility can warehouse the data for on-line access requirements for both the customer and for transporting data in XML format to a retailer.

**Figure 4: SMS Applications and Information Flow**




**Note:** Once the meter data transports the reads through the SMS to the data repository, all services beyond basic customer presentment of usage information, such as load control/cycling, messages to smart thermostats, and enhanced web presentment, are considered enhanced services and are not part of the minimum SMS requirements.

### 4.3.1 Minimum SMS 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.

The Board considered bi-directional communication as a minimum requirement. It concluded that specifying bi-directional communication eliminated viable systems from contention and could compromise competitive bidding. Therefore, the Board did not include it as a basic requirement. Also, the basic system proposed by the Board does not include all of the technical features that are currently available from vendors.

### 4.3.2 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-3.

## 4.4 Minimum SMS 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 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 are used, the system must have a two-way communication link between the communication module and the collection computer to reconfigure the unit to comply with any changes in ToU and/or CPP periods.
- 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 (if this feature and two-way communication link exists) 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-4.

- 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.

- Hourly reads and pricing changes of the TOU and CPP registers must, if necessary, 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-5.

- Distributors must choose systems that have a proven track record in the field, with at least 10,000 units that comply with the proposed technical requirements installed and working.

- The architecture of each SMS must include sufficient redundancy to ensure the integrity of data collection and adherence to performance specifications outlined in this document. See Appendix D-6 (*Smart Meter Technology requirements*).

- Read transmission success rate must be over 95% over any three-day period.

- Missing reads must be logged and reported through the system by 6 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-7 for an outline of proposed E&R requirements.

- The system must be able to construct the peak hourly demand for Group 2 customers. 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 SMS specification standards.[6]

### 4.4.2 Smart Meter Data Collection Computer (SMDCC) Monitoring & 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.

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

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; and
- Problems verifying reconfiguration of time parameters for systems using TOU data.

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 SMS Reports, are delivered after the nightly read transmissions.

**Minimum Non-Critical SMS Reporting**

- Successful initialization of modules installed in the field;
- Discrepancies in module and CIS links;
- Successful capture of readings – benchmark of the 95%;
- Read reports;
- Alarms and status indicators at modules;
- Suspected tamper and trending reports;
- Unsuccessful capture of readings – benchmark of less than 5%;
- Communication link functionality monitoring; and
- Status indicators for regional collectors.

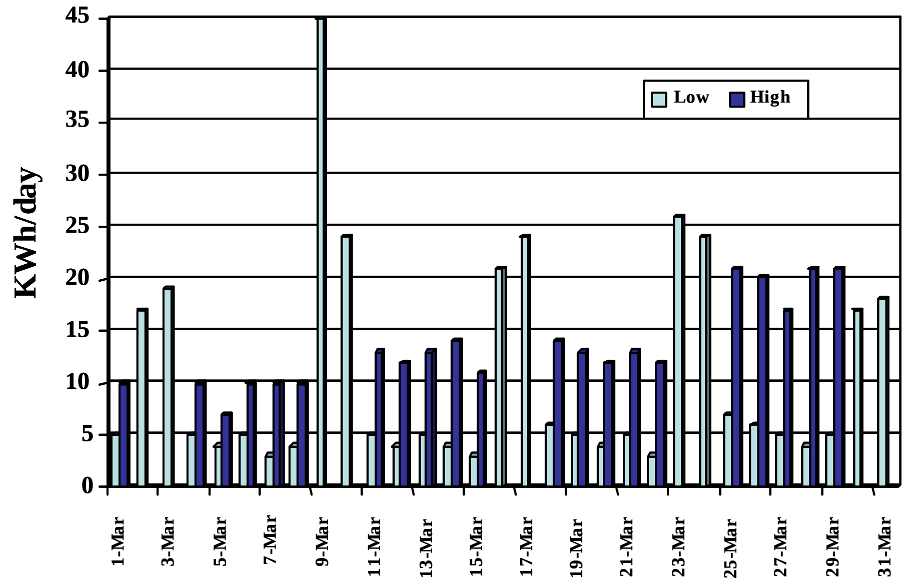
For the basis of the smart metering system request for proposal, see Appendix D-6.

## 4.5 Customer Information

For Ontario to meet its goal of 5% demand reduction by December 2007, 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 5: 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 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 IMO 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-8.

**Customer Usage Information Access Options**

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-9.

## 4.6 Information Detail Parameters To Third Parties

Retailers will have access to the same level of data as 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.

### 4.6.1 Standard Format for Data

This report 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 that was built 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 implementation coordinator would 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

The Retail Settlement Code states that two years of customer usage data must be available. Smart metering data that has been validated and used to calculate and settle the bill should be available online. An additional seven years of data should be available off-line.

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.

For alternate options for distributors on SMS system management and data collection operations, see Appendix D-10.

## 4.7 Distributor Guidelines for RFP Development

The inherent strengths and weaknesses of each SMS are based to a large degree on the telecommunications medium used to transmit the data. Diversity in the type of customer base, demographics and telecommunications infrastructure availability will necessitate distributors selecting 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 SMS selection as it will determine system performance and ultimately the overall cost per point of the entire SMS. The information in Appendix D-11, provides more structure, technical information and functionality guidelines on the various vendor SMS options available to distributors, while at the same time taking into consideration meter proximity and telecommunications infrastructure availability.

It must be noted that the information contained in Appendix D-11 is a guideline only. Specific SMS vendors may have overcome some obstacles noted as impediments to achieving the required functionality.

# 5. Non-Commodity Time of Use Rates

The Minster asked the Board to address the need for and potential effectiveness of the introduction 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 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:[7]

- Delivery (transmission and distribution),
- Regulatory costs (wholesale market operations 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.

[7] 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.[8] 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.[9]

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.

[8] 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.
[9] 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.

Bill 210 froze transmission rates. The legislation has since been amended to allow the Board to adjust wholesale transmission rates. However, under the current rate freeze distributors cannot adjust the retail transmission rate to reflect a wholesale transmission price change.

### 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).

In 2002, Bill 210 froze distribution rates. Distributors may not apply for rate increases without the approval of the Minister of Energy.[10] In anticipation of the freeze being removed by the government effective in 2006, the Board has initiated a project to review the revenue requirements of distributors. That project does not include a fundamental re-examination of the design of distribution rates.

### 5.1.3 Preliminary Assessment

A primary principle of regulatory rate design 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.

If 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.

[10] In 2004, distribution rates were adjusted to recover the first portion of Regulatory Assets. In 2005, distribution rates will be increased to allow recover of the last 1/3 of the Market Adjusted Revenue Requirement (if distributors commit these funds to a conservation plan).

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.

[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 IMO 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.

## 5.2 Regulatory Charges

Under the new bill format introduced recently for low-volume consumers, regulatory charges comprise (a) a wholesale market operations 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 Operations Charge

The wholesale market operations charge covers primarily various costs incurred in the wholesale electricity markets administered by the Independent Electricity Market Operator (IMO). 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 IMO-administered wholesale electricity markets that are not captured in the hourly price of energy and that must be recovered by the IMO. There are three categories of such costs:

- Costs that vary hourly (payments by the IMO for operating reserve, congestion management, transmission line losses, and intertie 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 IMO (staff, premises, systems).

Collectively, these costs are referred to as IMO "uplift." Hourly uplift is the single largest component of the IMO's 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 IMO started charging uplift to all wholesale customers, including distributors. The Board authorized distributors to charge their customers $0.0062 per kWh (to cover IMO 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.

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

By November 2002, the amount paid by distributors to the IMO 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 IMO 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 IMO uplift in any month and the amounts collected by distributors are now charged or credited to Ontario Electricity Financial Corporation (OEFC).

#### 5.2.2 Preliminary Assessment

The IMO 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 IMO 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 IMO 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.

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

# 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 draft 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. The Minister must approve the plan.
2. The implementation 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. If necessary, licence conditions could be amended to specify 2007 and 2010 targets. The Regulated Price Plan will establish time-dependent pricing and a timeline for implementation.
4. 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. Distributors must also begin to develop their business processes around procurement, internal schedules and deployment.
5. 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.