Ontario Energy Board

Smart Meter
Implementation Plan

Report of the Board
To the Minister

January 26, 2005

Smart Meter Implementation Summary

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

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

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

Proposed smart meter system

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

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

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

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

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

Rollout of smart meters

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

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

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

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

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

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

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

Responsibility for implementation

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

Ministry of Energy

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

Ontario Energy Board

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

Distributors

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

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

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

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

Program Coordinator

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

Independent Electricity System Operator (IESO)

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

Vendors

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

Impact on customers

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

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

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

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

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

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

Cost

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

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

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

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

concentrated around the institution and at specific times of the year so that economies of scale apply and the cost per read is much lower than the $25 referenced above. For these situations, the cost group estimated the read cost at $2.00 to recognize that many reads in the same area on the same day provide some economies of scale. Because of the variability of LDC customer bases that drive final read costs, it is hard to draw average per customer savings conclusions. In the university town example, 20% of the customer base might move in a year but using $2.00 per read and spreading the cost back over the entire customer base results in a savings attributable to AMR reading of $0.07 /meter/month. ($2.00 *.2 * 2 reads/12 months).

For other less mobile customer bases, 3% mobility might be more applicable but the higher cost of $25 per final ready might apply. In this case the cost averaged over the entire customer base would be $0.06 /meter/month ($25 * .03/12).

Because this second mobility might also apply generally to the university town situation the total savings per customer per year in that situation would be the sum of the two or $0.13 /meter/month. Thus the range of savings for check and final reads is taken to be $0.06 to $0.13. The actual cost of the AMR reads has not been subtracted from the savings because it would be nominal when spread over the entire customer base.

Benefit #9 – Cash Flow Improvement

Many utilities bill residential customers bimonthly or quarterly and some believe that monthly billing would improve cash flow for the LDC and result in financing savings. Automatic meter reading would support more frequent billing because the billing data would be available which would not be the case in a manual system where the meter is read less frequently. The financing savings arise from the fact that customers who are billed only bimonthly are carried by the LDC because electricity billing is in arrears not in advance. For a customer bill of $100 per month at a weighted average cost of capital of 8.3% this financing cost is $0.70 per month ($100 * .083/12). For bimonthly billed customers that are switched to monthly billing, there would be six of these occurrences that could be saved per year resulting in an average savings per month of $0.35. However, these savings are offset by the cost of preparing and delivering the extra six bills per year and of processing the payment received. Bill preparation, mailing and processing cost is estimated at $1.00 per event so that the average cost increase for six more bills per year would be $0.50 per month which is higher than the cost of financing customers on bimonthly billing.

For this reason, the cost group concluded that there were no net cash flow savings available from more frequent billing.

Benefit #10 – Theft of Power Detection

Theft of power by tampering with the meter is detectable by most electronic meters and reportable over an AMR system. Electromechanical meter tampering, by contrast, requires a manual inspection to detect, one usually performed by meter readers presently. To the extent that smart meters detect more of these instances of tampering than meter readers do, there could be a benefit.

In Ontario, the more common mode of theft is by meter bypass and that is not detectable by smart meter systems. Bypass consists of attaching unauthorized conductors to the secondary supply wires on the line side of the meter. Power is then diverted before it enters the meter. Doing this on overhead systems is relatively easy but it is also fairly easy to spot because hiding the illegal conductors is a problem. Attaching to underground conductors requires more effort and skill but when properly done it is almost impossible to detect without gaining access to the inside of the house. Presently, meter readers make visual inspections of meters and overhead systems as they visit each location. Many illegal bypasses of overhead systems and tampering with the meter are detected by this method.

Some hidden connections such as those inside the meter base are not easily detected by visual inspection but will be detectable by smart meters because the meter has to be removed to get at the base and this disturbance of the meter triggers a tampering message that is read by the AMR. Old connections that are cleverly concealed may be revealed during smart meter conversion as the old meter is removed and the base exposed. The project is expected to yield some benefits then as longstanding bypasses are eliminated. Initial installation of smart meters is expected to yield benefits because many of these invisible connections will be revealed when the old meter is removed. On the other hand, once it becomes generally known that meter readers are no longer making visual inspections, the incidence of bypass might increase and this is not detectable by smart meters as long as the meter is not disturbed.

In terms of benefit to the LDC, elimination of theft will increase revenues but the utility was not necessarily losing that revenue before smart meters. This is because LDCs are permitted an uplift on consumption to recover system losses of which theft forms a part. The amount of uplift is based on 1995 to 1999 losses so theft instituted prior to that time is already included in the recovery. As rebasing occurs, system losses are updated and the uplift charge adjusted accordingly. Ultimately the benefits of reducing theft flow to the customer by way of lower rates.

Bypass theft has increased since 1999 with the proliferation of grow houses. These losses are not being totally recovered in the uplift because they did not exist in the base year data. Therefore, LDCs are under collecting energy charges from customers and financing the cost of uncollected losses. To the extent that the bypass is discoverable during smart meter deployment, LDCs will realize some benefit in more complete recovery of power costs. However, many grow operators deliberately choose underground residential systems in which to locate simply because detection of the illegal bypass is much more difficult than with overhead systems.

Beyond the initial detection benefit from smart meter conversion already mentioned, ongoing savings from theft of power detection are not expected because smart meters are no more able to detect bypass than the existing electromechanical ones. The fact that some overhead bypass is discovered by meter readers now and that this benefit will be lost with the introduction of smart metering, led the cost study group to conclude that cost savings would not materialize in this category.

Other studies put the value of theft detection much higher. The CERA study, for example, suggests a range of from $0.10 to $1.33 USD per meter per month. The high part of this range would translate into about $1.66 per month in Canadian dollars using an exchange rate of 0.80. For an average suburban customer consuming about $50 in commodity a month, this amount of theft would exceed the entire uplift charge for all LDC system losses[9] not just theft. The cost group decided that it must be based on a theft experience unknown in Ontario and therefore excluded it as inapplicable. The lower part of the range might be reasonable if meter tampering is the predominant method of theft. However, even if that is the case, amateur attempts at tampering are often detectable by meter readers now and professionals will prefer bypass because it is undectable by any meter. Accordingly, even the low end figure appears to be too high to the cost group.

The final consideration is whether or not higher resolution of meter data might assist an LDC in detecting theft. Presently, billing systems can be programmed to spot suspicious changes in consumption patterns that might indicate that an illegal bypass has just been made. A field check of demand is then made by comparing clip on ammeter readings at the supply transformer end of the secondary conductors with the indication on the meter. Some advantage will accrue to having remote readings for the meter end in this case particularly if approaching the customer's residence might be dangerous. The field investigation would still be necessary to confirm bypass though.

The group heard suggestions that comparing consumption patterns between customers in the same neighbourhood might reveal theft. This idea has some potential in the case of grow operations which are usually sophisticated enough to simulate normal consumption by connecting some load through the meter. Right now detection of an unusual daily pattern of that metered consumption is not possible because only monthly consumption data is available. Smart meters will allow construction of daily consumption patterns and it is not unlikely that grow operations will exhibit some identifying characteristics. Detailed studies will be needed to validate the technique before it can be used, though, and the cost group was hesitant about ascribing benefits to a strategy that might be defeated by installing timers on loads to simulate a normal consumption pattern.

It is possible to detect theft if the supply transformer has its own meter which can then be compared to the totalized readings of customer meters supplied by it and in that case remote reading capability is a definite advantage. However, there are

[9] Assuming an average uplift of 3% for losses most of which is attributable to line and equipment losses not theft.

technical and cost hurdles to be overcome with this idea and any utility considering it would probably be better off just installing all customer meters at the transformer secondaries and eliminate the possibility of bypass altogether.

Overall, the cost group doubts that any real benefit will accrue from smart metering in the area of theft detection and so has attached no value to it.

Benefit #12 – Improved Outage Management

Smart meter data and communication capability are the basis for improved outage management claims. To analyze the benefits, outages need to be broken down into their constituent stages. The cost group chose three stages for this purpose:

Notification of LDC operators that a customer is out of power is the smallest time consuming part of the event and usually occurs through the utility's SCADA system that reports equipment status or through a telephone call from the customer. In either case, operators are usually aware of an outage very quickly after its initiation. Notification through an AMR system through normal meter reading activity could not be relied on because the read would probably not coincide with the outage. If smart meters have no voltage sensing features that initiate a call to the AMR then this could be relied upon for notification but, otherwise, routine meter read polling would probably not coincide with an outage so would be of no value in notification. In either event, any economies realized through faster or more comprehensive notification by smart meters would not be a significant benefit because this phase of the outage is such a small part of the overall outage time.

Dispatch and Repair is the part of the outage that consumes the most time. If the outage is very widespread due to a lot of equipment damage that might occur in severe storms then the dispatch of crews and efficient management of repairs can be a complex task. No voltage information from meters could be useful in these cases if integrated into automated mapping systems so that an operator had a graphical display of the parts of the system that are out of service. However, widespread outages of this kind are rare in most utilities. The predominant outage is usually related to vehicles hitting poles or transformers or an equipment fault caused by isolated lightning strikes or tree branches making contact with overhead conductors. These outages do not generally require more than one or two line crews to effect repairs and do not pose complex labour and equipment management issues that would benefit from smart meter data. For most outages, meter data information would probably not add any appreciable efficiency to the repair effort.

Restoration of service once repair has been completed involves reenergizing the system and checking to see if all customers are restored. In radial systems prevalent in rural areas, laterals can often hide equipment damage that was not detected during the initial line patrol and these situations are the ones in which customers can be overlooked at restoration time. Polling meters in these cases would be helpful to detect that damage.