14 Carlton Street
Toronto, Ontario
M5B 1K5

Telephone: 416.542.2572
Facsimile: 416.542.2776
rzebrowski@torontohydro.com

toronto hydro
corporation

August 11, 2004

via courier

John Zych, Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 26th Floor
Toronto, Ontario M4P 1E4

Dear Mr. Zych:

Re: Minister's Directive on Implementing Smart Electricity Meters in Ontario RP-2004-0196

I write on behalf of Toronto Hydro Corporation (Toronto Hydro) and further to your letter dated July 19, 2004. We enclose five (5) copies of Toronto Hydro's comments on the Minister's Directive on Implementing Smart Electricity Meters in Ontario, along with an electronic copy in PDF format, as required.

These comments are supplementary to those contained in our letter to you dated August 10. The requisite five (5) copies of this letter along with an electronic copy in PDF format, are also enclosed.

Please direct any questions or comments to the undersigned.

Yours truly,

(Colleen Richmond for)
R. Zebrowski, Vice-President
Regulatory Services

CC: David O'Brien, President & CEO, Toronto Hydro Corporation
Peter D'Uva, Senior Vice President, Customer Services
Steve Andrews, Senior Manager, Communications & Public Affairs
Richard Lü, Vice President, Environmental Health & Safety

Implementation Plan for Smart Meters in Ontario

Comments of Toronto Hydro Corporation

1. INTRODUCTION AND PAPER OVERVIEW

1.2 Scope

- The focus of the smart metering implementation plan should be on the identification of two or three AMR technologies, with the associated metering devices, that are technologically viable, and not cost prohibitive for full-scale deployment across Ontario. Technical viability must include functional, performance, and reliability. It should be determined through strategically chosen pilot projects across the province to include city and rural settings, as well as other situations that could adversely impact the performance of the communication media to be deployed.

- If it is deemed that dynamically changing the time-of-use periods would serve the purpose of conservation and demand management in a cost effective way, extensive testing must be carried out to ensure the technologies to be deployed are functional and reliable. Unlike the pre-defined time-of-use period functionality, the dynamic time-of-use functionality would be new. The associated information system functionality to process the data for billing would also be much more complex than what is currently available for fixed-period time-of-use rates.

- Dynamically changing the time-of-use period would be necessary if Critical Price Period (CPP) billing is to be implemented. The technology to inform consumers of the CPP would also have to be implemented. If this functionality were to be incorporated into smart metering, the two-way AMR system would have to be able to direct the information to some suitable display mechanism inside the consumer's house. This would be additional new functionality not commonly available with the current AMR technologies. The information system to properly manage all the logistics of re-configuring the metering device and informing the consumers of the CPP would also have to be tested and implemented.

2. BACKGROUND

2.2 Advanced Metering Considerations

2.2.1 Benefits for Customers

- With time-of-use rates implemented for non-commodity charges such as distribution charge and transmission connection/transformation charge, consumers will have even greater control over their bill, and that would more effectively motivate them to shift their peak demand (kW and kVA) to reduce the system peak demand.

2.2.5 Benefits for Distributors

- Most of the benefits cited are the results of AMR, and are not directly related to the metering function. Some of these functions may have additional associated costs that need to be considered separately.

3. ESSENTIAL ELEMENTS OF AN IMPLEMENTATION PLAN

3.1 Procurement Strategy

- The strategy must take into consideration that the metering devices may not be independent of the AMR technologies deployed by utilities. It is highly unlikely that all the utilities in Ontario would deploy the same AMR technology. Some AMR technologies may accommodate meters from all four major manufacturers. Other AMR technologies, which may be superior in functionality, performance and cost, may work only with meters from certain manufacturers.

- It is unlikely that there would be more than two or three AMR technologies that are technically viable and cost effective for deployment in Ontario. The Ontario procurement strategy should involve procurement coordination among utilities that have the same AMR technologies. The largest utility in each group could perform the procurement function on behalf of all of the other utilities in the group.

3.2 Implementation Priorities

3.2.1 All over 50 kW

- If interval metering were to be implemented for all consumers over 50 kW, the volume of data for the larger utilities would be difficult for their existing interval meter data systems to handle.

- Currently, interval metering systems deployed by utilities are telephone-based. These systems would be stretched to their limits with over-50kW interval metering for the five largest utilities. New AMR technologies would be necessary to properly support the additional interval meter customers.

3.2.2 New Homes

- Installing smart meters for new homes would first require that the smart metering technology, including the AMR system and the meter data management system, has been thoroughly tested to be able to meet the functional, performance and reliability requirements for the utility’s future full deployment.

- After the smart metering technology has been selected, smart meters could be installed at new homes. However, when these smart meters are installed at new homes, they may not be immediately reachable by the AMR system that is being deployed. These smart meters would operate as regular meters if the AMR system being deployed does not yet reach them.

3.2.3 Congested Areas

- For congested areas such as the Toronto downtown core, it would probably be more effective to concentrate on installing interval metering for all customers above 200kW using the existing interval metering technology, which has been in use at least for the past ten years. These are likely the customers that are large enough to justify implementing Demand Response controls for their electrical facilities to take advantage of the hourly spot prices.

- Smart metering for the remaining consumers should be incorporated into the smart metering rollout plan.

3.2.4 Self Selection

- Same comments as for New Homes

3.3 Interim Targets

- The Ontario smart metering deployment Schedule must take into consideration the successful testing of viable technologies to meet the functional, performance and reliability requirements. Pilot testing of the various technologies should be carried out in strategically selected locations across the province. Thorough testing of multiple technologies to select viable options, and modifications to systems to meet Ontario requirements, will likely take 9-12 months.

- The smart metering deployment schedule should also take into account the time required to properly specify the smart metering functional, performance, reliability, and testing requirements. This would form the basis for a successful deployment of smart metering across the province.

- Investigate the feasibility of one target implementation date (December 31, 2010). This would allow the larger utilities to manage their workload installations each year in a cost effective manner.

3.4 Process Driver

- To be effective in the deployment of smart metering across the province, it is important for an OEB-sponsored agency to coordinate the effort. However, each utility should drive its own smart meter implementation work based on its work management process.

4. COST RECOVERY

- Even though smart metering seems to imply some suitable AMR technology, it is still important to explicitly identify the costs of AMR that enable smart metering, since AMR would be a significant component of the smart metering cost. This is important since the utility's normal meter replacement program would likely not have included an AMR system. AMR would incur costs that would have to be funded beyond the normal metering capital budget.

- A very significant cost that needs to be recognized explicitly is that for information system enhancement or replacement to enable smart metering. The information systems affected include those for meter data management, meter data processing for billing/settlement, and billing. If interval metering is implemented for all consumers, or even just for all consumers above 50kW, the largest utilities in the province would most likely have to enhance or replace their existing interval meter data management and processing systems.

- It would be difficult to quantify the financial benefits from reduced theft of power, lowering of losses, etc., in order to reflect the related dollar amounts into the cost recovery.

- Theft of power is often carried out by tapping into the line before the meter. With smart metering technology, there would be fewer onsite visits by utility staff. This might in fact increase the chance for theft of power.

4.1 Meter Charge

- Smart metering should be considered part of the distribution system asset. As such, the capital costs incurred should be incorporated into the distribution rate base for the relevant consumer classes.

- Alternatively, the smart metering costs could be recovered from DSM funding, since smart metering is necessary for DSM.

4.2 Third Tranche

- See comments for section 4.1

4.3 Combination

- See comments for section 4.1

4.4 Third Party Provision

- Third party funding could minimize the initial capital outlay. With a reasonable rate, the monthly repayments could be accommodated with a small distribution rate increase. The advantage of this arrangement is that the consumers benefiting from smart metering will be paying the cost over the future period when they derive the benefits.

5. METERING FUNCTIONS

- The functional requirements should be divided into the following categories:

    - Core metering functions
    - AMR requirements
    - Additional/optional metering functions
    - Typical load control support functions

- Core metering functions should include all the necessary usage measurement functions to support billing/settlement, and to enable conservation and DSM.

- AMR requirements are the minimum set to support the meter data collection functional, performance and reliability needs, as well as the typical load control functions.

- Additional metering functions are those that might be implemented by utilities that could cost justify them to improve their operations. They are generally not required for usage measurement to support billing or DSM.

- Typical load control support functions would allow the implementation of load control of consumers' interruptible appliances and electrical facilities.

5.1 Measurement

- The requirement to at least support pre-set time-of-use and seasonal rates, (at least two-season and three time-of-use rates with weekday/weekend/holiday schedules), is probably not controversial. This functionality, for both kWh and demand, has been around for many years, and should not present an issue.

- CPP rate support would require remote re-configuration of the time-of-use periods in a dynamic manner (24 hours ahead, for example). There are significant complexities introduced to the metering device, the data management system, and the meter data processing for billing/settlement, even though the billing system itself may just treat the CPP period as another time-of-use period.

- If CPP rate support is deemed necessary, rather than incurring all the complexity of enabling remote dynamic reconfiguration of the time-of-use parameters, it might be more tenable to install meters with interval metering capabilities, assuming that the price difference between an interval meter and a time-of-use meter, particularly the one that supports dynamic reconfiguration remotely, is small. The interval metering function could be turned on for the customers eligible for CPP rate or for other rate structures requiring interval metering. The additional processing complexity would be limited to the meter data processing system.

- To fully support the CPP rate, either the smart metering AMR system or some other mechanism would be needed to provide notifications to customers when the CPP would be in effect.

- For residential and small commercial customers, hourly interval would be sufficient if interval metering is deemed to be necessary for smart metering. For the larger customers (over 200kW), 15-minute interval would still be necessary to prevent intentional peak splitting.

5.2 Reporting

5.2.1 To Billing Entity (Utility)

- There would be an issue with prepayment meters contravening the Measurement Canada rule which prohibits retroactively changing the commodity price. The card purchased cannot predict future CPP activities and it would not include the future CPP commodity prices. When the card is swiped on the meter, it would not contain the CPP commodity prices when the electricity is consumed during the CPP duration. In general, any dynamically changing pricing scheme would be difficult to implement with the prepayment meter, unless it has remote update capability supported by the appropriate AMR system.

- The regular time-of-use meters with pre-defined time buckets would not support the CPP rate. See comments for pervious section. Similarly, the normal walk-by or drive-by wireless reading would not support the CPP rate. It is not practical to send meter reading crews out 24 hours prior to the CPP to reconfigure the time-of-use periods for CPP.

5.2.2 To Consumer

- The ideal way to provide pricing and consumption information feedback to the consumer would be by using a wireless display unit installed at some convenient location within the consumer's premises. This will require two-way communication from the AMR, and wireless communication from the metering device to the display unit. The feedback information could also come from the meter data warehouse, if the meter information is retrieved frequently enough from the meters.

- The technology alluded to above needs thorough testing to ensure all the functional, performance and reliability requirements are met.

- Using the Web or television to provide pricing and consumption information may be good for certain consumer segments, but may not be suitable for the general consumer base.

5.3 Data Storage

- Data storage, data management and data processing should all be considered. If interval meter data were to be stored and managed, even for hourly intervals, there would be significant impact on the larger utilities. For the five largest utilities, it is almost certain that the existing interval meter data systems would require major enhancement or even replacement, with significant expenditures incurred.

- The concept of a single Ontario meter data warehouse should be supported. The ability of such a system to meet the functional and performance requirements must be carefully tested. The system must be able to support all the existing utility requirements in terms of meter maintenance, billing, customer service, and retail settlement. A comprehensive set of specifications that covers functional, performance, and testing requirements must be prepared.

- Adequate time must be allowed for the specification, development, testing, and implementation of the meter data management system, whether it is an Ontario meter data warehouse, or the enhanced/replaced utility meter data management system. Cost recovery for the expenditures incurred must also be properly included in the funding of Ontario smart metering.

5.4 Bi-directional Communication

- Bi-directional communication will be necessary to provide information feedback to consumers, to remotely configure the metering devices for some dynamic pricing structure, and to enable load control.

6. OWNERSHIP

- Meters should be owned by the utility. If other parties own the meters, and assuming owners have full access to the meters and can grant full access to other parties, the meters could be re-configured without the knowledge of utility staff and the result could compromise the utility's ability to use the meter data for billing, settlement and other necessary functions.

- Planned meter maintenance program would be difficult to implement in an efficient manner if the meters have different owners.

- Meters are utilities' only means to determine actual electricity usage to bill customers, and are part of the distribution system asset. The utility should have full responsibility and control over these devices. As such the utility should be the owner of the metering devices.

- At the very least, the decision of ownership should lie with the utility based on its business case analysis taking into consideration full costing, which must include meter cost, maintenance, and service for the life of the meter.

7. OTHER CONSIDERATIONS

7.1 Measurement Canada Requirements

- The first bullet in the section indicates that the telemetering devices that establish a legal unit of measure outside of an approved meter must be approved. This would seem to be pertinent for an AMR system such as the ITRON system. If the ITRON CCU has not yet been approved by Measurement Canada, and if a utility has selected the ITRON system to implement smart metering, then the approval period for the CCU would have to be reflected in the smart metering implementation timeline.

- The second bullet indicates that the interval data including the combined energy and timestamp information must be retained in an approved meter until it has been downloaded. This seems to render the ITRON type of system not acceptable for revenue metering. This point needs to be clarified with Measurement Canada.

7.2 Production and Installation

- See comments for section 3.3

- For the larger utilities to properly carry out the smart meter installation work for the numbers that greatly exceed what they would normally handle, appropriate work management processes supported by some work management system will likely be necessary. The meter information data entry to and from the meter information management system also needs to be automated as much as possible.

- Utilities should be allowed to continue to operate their existing interval metering systems.

- Utilities should be allowed to make their own decision on whether an interval meter should be implemented on the existing system or the new smart metering system.

- Utilities should be allowed to plan their eventual migration of the existing interval metering system to the new smart metering system when the latter has matured.

- A minor point: Enel installs 40,000 meters per day, and not per month, with 7,000 installers.