EB-2012-0100

ONTARIO ENERGY BOARD

IN THE MATTER OF subsections 78(2.1), (3.0.1), (3.0.2) and (3.0.3) of the *Ontario Energy Board Act, 1998;*

AND IN THE MATTER OF subsection 53.8(8) of the *Electricity Act, 1998;*

AND IN THE MATTER OF Ontario Regulation 453/06 made under the *Ontario Energy Board Act, 1998;*

AND IN THE MATTER OF an Application by the Independent Electricity System Operator as Smart Metering Entity for an Order fixing a Smart Metering Charge for July 1, 2012 to December 31, 2017.

APPLICATION AND PRE-FILED EVIDENCE

March 23, 2012

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EXHIBIT LIST

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B

ONTARIO ENERGY BOARD

IN THE MATTER OF subsections 78(2.1), (3.0.1), (3.0.2) and (3.0.3) of the *Ontario Energy Board Act, 1998;*

AND IN THE MATTER OF subsection 53.8(8) of the *Electricity Act, 1998;*

AND IN THE MATTER OF Ontario Regulation 453/06 made under the *Ontario Energy Board Act, 1998;*

AND IN THE MATTER OF an Application by the Independent Electricity System Operator as Smart Metering Entity for an Order fixing a Smart Metering Charge for July 1, 2012 to December 31, 2017.

APPLICATION

1. The applicant, Independent Electricity System Operator (the "IESO"), is a corporation without share capital continued under Part II of the *Electricity Act, 1998* ("*Electricity Act*"). The objects of the IESO include to plan, manage and implement, and to oversee, administer and deliver, the provincial government's smart metering initiative.

2. On March 28, 2007, the IESO was designated as the Smart Metering Entity ("SME") by Ontario Regulation 393/07 made under the *Electricity Act*. The regulation came into effect on July 26, 2007.

3. The IESO was granted an interim SME licence on September 14, 2007 and a permanent SME licence on January 27, 2011. The licence is valid until January 26, 2016.

4. In its role as the SME, the IESO is managing the development of the meter data management/repository (the "MDM/R") to collect, manage, store and retrieve information related to the metering of customers' use of electricity in Ontario.

5. The IESO, in its capacity as SME, hereby applies to the Board for an order:

(a) under subsections 78(2.1), (3.0.1), (3.0.2) and (3.0.3) of the *Ontario Energy Board Act, 1998* (the "*OEB Act*") fixing just and reasonable rates for the SME; in particular, approval of:

(i) a monthly Smart Metering Charge ("SMC") of $0.806 per Residential and General Service <50kW Customer to be charged to all licenced electricity distributors for the period July 1, 2012 to December 31, 2017;

(ii) an annual automatic adjustment mechanism to update the billing determinant with the annual changes in the number of Residential and General Service <50kW Customers listed in the OEB Electricity Distributor Yearbook;

(iii) a variance account to deal with changes in the SME's costs, or any revenue surplus or deficiency; and

(b) under section 5.4.1 of the Distribution System Code approving the Smart Metering Agreement for Distributors (the "SME/LDC Agreement") for use by the SME and local distributor companies ("LDCs").

6. The SMC will cover costs of the SME in the conduct of its activities *and* the costs of the IESO incurred prior to its designation as SME. As a non-profit

corporation, the SME has not included in the SMC, and is not seeking approval for, a rate of return.

7. In preparing this application, the SME has consulted with the Electricity Distributors Association ("EDA") and representatives of LDCs. The SME has been advised by the EDA and LDC representatives that the utilities anticipate proposing that the Board initiate a proceeding on its own motion to issue an order to implement recovery of the then-approved SMC in the rates of all distributors, in order to avoid the inefficiencies inherent in requiring every utility to file its own application for that rate component.

8. The SME also consulted with representatives of LDCs and the EDA in developing the SME/LDC Agreement. The SME has the support of the EDA with respect to approval of the SME/LDC Agreement subject to the Board:

(a) endorsing the proposed approach to liability management contained in Article 7 of the SME/LDC Agreement and providing LDCs with a regulatory mechanism to promptly recover through rates prudent costs incurred by an LDC in the event of an MDM/R failure that disrupts the LDC's operations;

(b) endorsing the SME's proposal that an LDC could seek review of an amendment to the MDM/R Terms of Service by bringing an application to amend the SME/LDC Agreement; and

(c) agreeing that the Board will determine any disputes between LDCs and the SME related to the SME/LDC Agreement that cannot be resolved through good faith negotiation as provided for in section 8.1 of the SME/LDC Agreement.

9. The SME has been advised by the EDA that the EDA anticipates requesting that the Board approve a deferral account for all LDCs to record prudent costs incurred as result of an MDM/R failure or to manage the risks of such a failure. The SME supports this request, but is not in a position to lead substantial evidence on the matter.

10. The SME proposes the following title for this proceeding: *Application for Approval of a Smart Metering Charge and the Smart Metering Agreement for Distributors.*

11. The persons affected by this application are all electricity distributors licensed by the Board and their respective ratepayers.

12. To effect individual service of this application on each such person would be very expensive. The IESO therefore proposes that notice of this application be given by the following means:

(a) posting this application on the IESO's website at the "IESO News and Notices", and "Regulatory Affairs" pages and the SME's website "Smart Metering System Implementation Program". This information will be automatically announced to all market participants and interested parties who are registered to receive IESO news and other communiqués;

(b) publishing a Notice of Application in an English and a French language newspaper in Ontario; and

(c) providing a copy to all intervenors registered in the SME's licence proceeding (EB-2007-0750).

13. The SME has provided pre-filed evidence in support of this application, which is identified in the Exhibit List. The SME may amend its pre-filed evidence from time to time, prior to and during the course of the Board's proceeding. In particular, should the SME identify a material change to its application the SME will update its pre-filed evidence and may also amend its submission to update the proposed SMC.

14. The SME may seek to have additional meetings with Board Staff and intervenors in order to identify and address any further issues arising from this submission, with a view to an early settlement and disposition of this proceeding.

15. The SME requests that a copy of all documents filed with the Board by each party to this proceeding be served on the SME and the SME's counsel in this proceeding, as follows:

(a) The SME:

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DATED at Toronto, Ontario, this 23rd day of March, 2012.

INDEPENDENT ELECTRICITY SYSTEM OPERATOR

By its counsel in this proceeding

Patrick G. Duffy

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A

BACKGROUND AND LEGAL AUTHORITY

16. The Smart Metering Initiative ("SMI") is the provincial government's policy of ensuring that Ontario electricity consumers are provided, over time, with smart meters. The goal of the SMI is to create a conservation culture and a toolset for demand management based upon the province-wide deployment of smart meters.

17. On July 26, 2006, the provincial government entered into an arrangement with the IESO under which the IESO would support the SMI by coordinating and project managing implementation activities for the MDM/R. The government also issued Ontario Regulation 452/06 (*Additional Objects of the IESO*) which added the following as objects of the IESO:

> 1. To plan, manage and implement the smart metering initiative or any aspect of the initiative.
>
> 2. To oversee, administer and deliver the smart metering initiative or any aspect of the initiative.

18. To carry out its role, the IESO established the Smart Metering System Implementation Program ("SMSIP"), the scope of which includes:

(a) development of the functional/technical specifications of the MDM/R requirements and associated business standards and processes;

(b) development and evaluation of a Request for Proposal for a turnkey MDM/R Contract;

(c) negotiation and management of the MDM/R Contract;

(d) acceptance testing of the MDM/R system functions and business processes;

(e) integration of LDCs' Advanced Metering Infrastructure ("AMI") and Customer Information Systems ("CIS") with the MDM/R;

(f) set-up and operation of the SME; and

(g) support of the provincial government's consumer education and awareness program

19. The MDM/R is a storage and data management system for smart meters that conforms to Ontario Regulation 425/06 (*Functional Specification for an Advanced Metering Infrastructure*) as amended by Ontario Regulation 440/07. The MDM/R is being utilized to collect, manage, store and retrieve information related to consumers' use of electricity in Ontario. It has the capability to receive smart meter read data from an LDC's AMI; validate, estimate and edit ("VEE") the smart metering data; and transmit billing quantities data back to the LDC for use in customer billing.

20. The first phase of the SMSIP was to select an operational service provider to develop and operate the MDM/R. After the completion of a competitive Request for Proposal process overseen by a Fairness Commissioner, the SME selected IBM Canada Ltd. ("IBM Canada") as the operational service provider for the MDM/R. The Fairness Commissioner's review (attached as Appendix "A" to Exhibit C-1) noted that:

> The IESO conducts procurement in a manner that stands the test of public scrutiny, encourages competition and reflects fairness in the spending of public funds. Competition among proponents is

> encouraged through open processes that afford vendors equal access to IESO procurement opportunities.
>
> [. . .]
>
> In conclusion, based on our review, we are satisfied that the MDM/R RFP process was conducted in a procedurally fair, open, and transparent manner. We detected no bias either for or against any particular Respondent in the application of the evaluation criteria. The evaluation criteria published in the RFP were applied objectively to each Base or Alternative Proposal using the process set out in the RFP.

21. The SME entered into the MDM/R Development Hosting and Support Agreement dated December 5, 2006 with IBM Canada (the "MDM/R Agreement"). A turnkey approach was taken under which IBM Canada is responsible for building and delivering and supporting the MDM/R. Under the MDM/R Agreement, IBM Canada is operating the MDM/R for an initial period of four years, from March 1, 2008 to March 31, 2012. The SME provided notice to IBM Canada under the MDM/R Agreement to operate the MDM/R for an additional two years ending March 31, 2014.

22. On March 28, 2007, the IESO was designated as the SME by Ontario Regulation 393/07 (*Smart Metering Entity*) under the *Electricity Act*. The regulation came into effect on July 26, 2007. The objects of the SME are specified in section 53.8 of the *Electricity Act* and include:

> 1. To plan and implement and, on an ongoing basis, oversee, administer and deliver any part of the smart metering initiative as required by regulation under this or any Act or directive made pursuant to sections 28.3 or 28.4 of the *Ontario Energy Board Act, 1998*, and, if so authorized, to have the exclusive authority to conduct these activities.

2. To collect and manage and to facilitate the collection and management of information and data and to store the information and data related to the metering of consumers' consumption or use of electricity in Ontario, including data collected from distributors and, if so authorized, to have the exclusive authority to collect, manage and store the data.

3. To establish, to own or lease and to operate one or more databases to facilitate collecting, managing, storing and retrieving smart metering data.

4. To provide and promote non-discriminatory access, on appropriate terms and subject to any conditions in its licence relating to the protection of privacy, by distributors, retailers, the OPA and other persons,

i. to the information and data referred to in paragraph 2, and

ii. to the telecommunication system that permits the Smart Metering Entity to transfer data about the consumption or use of electricity to and from its databases, including access to its telecommunication equipment, systems and technology and associated equipment, systems and technologies.

5. To own or to lease and to operate equipment, systems and technology, including telecommunication equipment, systems and technology that permit the Smart Metering Entity to transfer data about the consumption or use of electricity to and from its databases, including owning, leasing or operating such equipment, systems and technology and associated equipment, systems and technologies, directly or indirectly,

including through one or more subsidiaries, if the Smart Metering Entity is a corporation.

6. To engage in such competitive procurement activities as are necessary to fulfil its objects or business activities.

[. . .]

23. Ontario Regulation 393/07 (*Smart Metering Entity*), as amended by Ontario Regulation 233/08, granted the SME the exclusive authority to carry out the following functions:

1. Specifying its database and system interface requirements and information and data transfer requirements.

2. Receiving smart metering data for the purpose of carrying out the functions in paragraphs 3, 4 and 5, including receiving other information necessary for those functions.

3. Providing all services, as specified by the Smart Metering Entity, performed on smart metering data to produce billing quantity data, including validation, estimating and editing services.

4. Managing access rights to smart metering data and data derived from smart metering data in a manner consistent with the objects of the Smart Metering Entity set out in paragraph 4 of section 53.8 of the Act.

5. Subject to subsection (2), maintaining and operating a database of,

i. smart metering data and other data that is necessary for the Smart Metering Entity to perform the exclusive functions referred to in paragraph 3, and

ii. data that is derived through the exclusive functions referred to in paragraph 3.

24. The *OEB Act* provides the Board with the legal authority to allow the IESO (in its role as SME) to incur and recover costs that fall into the following two categories:

(a) costs incurred by the IESO prior to its designation as SME on July 26, 2007, which are recoverable through a Board order under subsection 78(3.0.3) of the *OEB Act* and Ontario Regulation 453/06; or

(b) actual and forecast costs related to the IESO's role as SME after July 26, 2007, which are recoverable through a Board order under subsection 53.8 of the *Electricity Act* and subsections 78(2.1) and (3.0.1) of the *OEB Act*.

25. Since the outset of its role in the SMI, the IESO has been tracking and recording the costs associated with the SMSIP and its role as the SME in accounts separate from the financial records for the IESO-controlled grid and the IESO-administered markets.

26. The MDM/R went live into production operations on March 1, 2008 with its first LDC. Further development and updates have continued and new functionality was released in 2009 and 2011. A release of further functionality is planned for 2012.

27. As of March 19, 2012, 70 LDCs and over 4.3 million smart meters were enrolled with the MDM/R. The MDM/R is receiving and processing reads from over 3.6 million smart meters on daily basis. The numbers of LDCs and meters

registered with the MDM/R continues to increase to meet the provincial government's objective of having all Regulated Price Plan customers enabled for time-of-use billing.

B

TRANSITION TO A NEW SME

28. The IESO was designated as the interim SME so that the IESO could leverage its expertise to bring the MDM/R into operation and support the provincial government's SMSIP under which eligible customers' meters will be registered under the MDM/R. In light of the IESO's transitional role, the IESO recognizes that measures need to be in place to ensure a smooth transfer of SME responsibilities from the IESO to an entity that performs the SME role on a permanent basis.

29. Given that the MDM/R is integrated into an LDC's "meter-to-bill" process, the IESO believes it is appropriate to transition the SME role from the IESO to the control of the province's LDCs. The IESO recognizes that LDCs must be fully engaged in the implementation of the SMSIP and the operation of the MDM/R if the provincial government's smart metering initiative is to succeed. For this reason, the involvement of LDCs in the governance of the SME is critical. This requires a transition plan that provides for LDC representation in MDM/R governance in the near term and a structure to transition the SME to LDC-control in the longer term.

30. The IESO, in collaboration with LDCs represented by the EDA, has developed a plan for the transition of the SME role that meets these objectives. The IESO has established a non-profit corporation under the *Canada Corporations Act* named The Organization for Smart Meter Services in Ontario (the "MDM/R Co.") that it will request be designated as the SME by regulation under section 53.7 of the *Electricity Act*. The IESO and the EDA entered into a Memorandum of Understanding providing LDCs with a role in the governance of the MDM/R

Co. Under the Memorandum of Understanding, as and when prescribed milestones are satisfied, and subject to government concurrence, the MDM/R Co. will become independent of the IESO. This transition is described in more detail below.

31. The IESO currently acts as the sole "member" of the MDM/R. Under the transition plan, the MDM/R Co. would initially be structured as follows:

(a) The board of directors of the MDM/R Co. consists of up to 11 members to be appointed by the IESO. A majority of board members will be representatives of LDCs nominated by the EDA to be appointed following:

(i) the Board's issuance of a permanent SME licence and approval of a Smart Metering Charge;

(ii) MDM/R Co. being designated as SME;

(iii) ratification of agreements between the IESO and the MDM/R Co.; and

(iv) relevant liabilities and assets transferred and contracts assigned from the IESO to MDM/R Co.

(b) The board of directors of the MDM/R Co. would oversee and direct the operations and management of the MDM/R Co. in the normal course, subject to unanimous votes on items identified in the Bylaw of the MDM/R Co.

(c) If the MDM/R Co. board was to be deadlocked, the IESO, as sole member, has the right to take action to resolve the deadlock.

Deadlock is defined as the circumstances where the MDM/R Co. Board's failure to make a decision that, in the opinion of the IESO, acting reasonably, jeopardizes the SME's ability to meet its obligations under the SMSIP. Should the MDM/R Co. become deadlocked, and following the replacement of the Board of Directors twice within a six month period, the IESO as sole member, may make the decision on the deadlocked matter.

(d) Officers of the MDM/R Co. would be appointed by the IESO on an interim basis and once in place, the board of the MDM/R Co. would have full authority to appoint all officers.

(e) The IESO would enter into a services agreement with the MDM/R Co. on a full cost recovery basis to provide services necessary for SME operations and implementation of the SMSIP and support the MDM/R Co. in the management of the MDM/R Agreement with IBM Canada.

32. Subject to the concurrence of the provincial government, the IESO will resign as sole member of MDM/R Co. and appoint replacement members after the following milestones/conditions have been met:

(a) IESO's Smart Metering Entity costs and associated obligations have been repaid; and

(b) the province's Time-of-Use billing objectives have been substantially completed (i.e., 3.6 million smart meter customers being billed on Time-of-Use).

33. The IESO has agreed to consult with the EDA on replacement members

and transition of governance prior to appointing replacement members and resigning as sole member of MDM/R Co. The IESO and the EDA have agreed to jointly seek government concurrence upon the meeting of the two milestones/conditions.

34. In light of the importance of protecting the privacy of data within the MDM/R, the IESO and the EDA have also committed to work, both individually and collectively, with the Information and Privacy Commissioner to address privacy concerns with respect to the MDM/R in a timely manner.

35. The plan for transitioning the SME role from the IESO to the MDM/R Co. and the SME/LDC Agreement have been endorsed by the EDA; the EDA supports the IESO's application to the Board.

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REVENUE REQUIREMENT

36. The revenue requirement of the SME from the inception of the SMI (July 2006) until December 31, 2017 is $239,341,798 plus financing costs. Financing costs are forecast to be $12,178,542, but would be subject to changes in interest rates. The total revenue requirement is therefore forecast to be $251,520,340.

37. The costs for the development and delivery of the MDM/R and the costs to operate the MDM/R make up the majority of the SME costs. The SME entered into the MDM/R Development Hosting and Support Agreement dated December 5, 2006 with IBM Canada (the "MDM/R Agreement"). A turnkey approach was taken under which IBM Canada is responsible for building and delivering and supporting the MDM/R.

38. Under the MDM/R Agreement, IBM Canada is to operate the MDM/R for an initial period of four years, from March 1, 2008 to March 31, 2012. The IESO has exercised its right to renew the MDM/R Agreement for two years (to March 31, 2014). The payments to IBM Canada are primarily fixed, based on a set of monthly payments to February 28, 2012, no charge for March 2012, and a per meter per month charge of $0.245 for the renewal period.

39. The principal assumptions underpinning the determination of the revenue requirement are:

(a) The period over which the costs were or will be incurred is from inception of the Smart Metering Initiative (July, 2006) to December 31, 2017.

(b) The period over which the costs would be recovered is based on the estimated asset service life for the MDM/R of approximately ten years; from the date it initially went into operation on March 1, 2008 to December 31, 2017. The service life is based on industry practice and is consistent with service lives used for comparable meter processing and database systems. Further development and updates have continued and new functionality was released in 2009 and 2011, with further functionality planned for release in 2012.

(c) There is no provision for costs associated with providing service to commercial and industrial meters, as at this time the SME does not have a basis for determining when commercial and industrial meters will be enrolled with the MDM/R nor any detailed requirements for providing that service.

(d) As a non-profit corporation, the SME has not included in the SMC, and is not seeking approval for, a rate of return.

40. The table below shows the actual costs against the program budget approved by the Ministry of Energy to February 2012 divided between the phases of the SMSIP.

Phase	Budget 2006 to Feb 2012	Actual 2006 to 2011	Actual Jan/Feb 2012	Actual 2006 to Feb 2012
Phase 1 (Inception to MDM/R Contract)	$ 1,538,000	$ 1,595,605	$ -	$ 1,595,605
Phase 2 (MDM/R Delivery)				
IESO Project Team Costs	$ 3,456,000	$ 3,396,478		$ 3,396,478
Extended IESO Project Team Costs Resulting from Delayed Delivery (Partially Funded by Liquidated Damages)	$ 1,620,000	$ 3,058,570		$ 3,058,570
Financing	$ 188,000	$ 197,866		$ 197,866
Expenses	$ 15,651	$ 15,651		$ 15,651
Total IESO Costs	**$ 5,279,651**	**$ 6,668,565**	**$ -**	**$ 6,668,565**
Vendor Base Contract	$ 10,600,000	$ 10,600,000		$ 10,600,000
Vendor Base Contract - PST	$ 864,000	$ 788,000		$ 788,000
Vendor Change Orders	$ 2,512,315	$ 475,377		$ 475,377
Vendor Change Orders - PST	$ -	$ 24,002		$ 24,002
Financing of Vendor	$ 313,000	$ 164,736	$ -	$ 164,736
Total Vendor Costs	**$ 14,289,315**	**$ 12,052,115**	**$ -**	**$ 12,052,115**
Total Phase 2 Costs	**$ 19,568,966**	**$ 18,720,679**	**$ -**	**$ 18,720,679**
Phase 3 (MDM/R Operation)				
IESO Project Team Costs	$ 8,512,308	$ 6,889,336	$ 659,504	$ 7,548,840
External Fees and Expenses	$ 1,028,349	$ 894,177	$ 65,902	$ 960,079
Regulatory Process: Licensing & Cost Recovery	$ 250,000	$ 93,036	$ -	$ 93,036
IESO Communications Support	$ 1,159,148	$ 742,730	$ -	$ 742,730
Total IESO Costs	**$ 10,949,805**	**$ 8,619,279**	**$ 725,406**	**$ 9,344,685**
Vendor Base Contract	$ 30,797,000	$ 26,926,352	$ 967,970	$ 27,894,322
Vendor Base Contract - PST	$ 2,095,632	$ 1,204,645	$ -	$ 1,204,645
Vendor Change Orders and Infrastructure Improvements	$ 1,793,905	$ (813,192)	$ (46,298)	$ (859,490)
LDC Testing Facilities			$ 63,623	$ 63,623
Total Vendor Costs	**$ 34,686,537**	**$ 27,317,805**	**$ 985,296**	**$ 28,303,101**
Transfer Budget to Unreleased Contingency	**$ (3,000,000)**	**$ -**	**$ -**	**$ -**
Total Phase 3 Costs	**$ 42,636,342**	**$ 35,937,084**	**$ 1,710,702**	**$ 37,647,785**
Phase 4 (Accelerated TOU Rollout Plan & OEB Mandate)				
IESO Project Team Costs	$ 5,779,405	$ 5,146,301	$ 167,285	$ 5,313,586
Vendor Costs	$ 3,270,595	$ 2,889,714	$ 180,954	$ 3,070,668
Total Phase 4 Costs	**$ 9,050,000**	**$ 8,036,015**	**$ 348,239**	**$ 8,384,254**
Release 7.2 and Measurement Canada 2011 Solution	$ 9,733,170	$ 7,099,919	$ 1,124,382	$ 8,224,301
Measurement Canada 2012 Solution and Required Upgrades	$ 2,916,097	$ 83,769	$ 237,961	$ 321,730
SME Corporate Costs	$ 63,058	$ 15,282	$ 2,931	$ 18,213
Provision for Changes to the MDM/R and Contingency	$ -	$ -	$ -	$ -
SUB-TOTAL	**$ 85,505,633**	**$ 71,488,352**	**$ 3,424,215**	**$ 74,912,567**
Financing Costs	**$ 3,488,684**	**$ 2,312,559**	**$ 231,687**	**$ 2,544,246**
TOTAL	**$ 88,994,317**	**$ 73,800,911**	**$ 3,655,902**	**$ 77,456,813**

41. The table below details the SME's revenue requirement from 2006 to 2017, divided between the four phases of the SMSIP. Each of these phases is described in more detail below.

	Actual	Forecast						Total
Phase	**'06 to '11**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2006 to 2017**
Phase 1 (Inception to Contract)	$ 1,595,605							$ 1,595,605
Phase 2 (MDM/R Delivery)	$18,720,679	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,720,679
Phase 3 (MDM/R Operation)								
IESO Project Team Costs	$ 6,889,336	$ 5,824,360	$ 5,946,758	$ 5,397,440	$ 5,646,488	$ 5,815,882	$ 5,990,359	$ 41,510,622
External Fees and Expenses	$ 894,177	$ 508,354	$ 480,390	$ 494,801	$ 509,645	$ 524,935	$ 540,683	$ 3,952,985
Regulatory Process: Licensing & Cost Recovery	$ 93,036	$ 250,000	$ 154,500	$ 159,135	$ 163,909	$ 168,826	$ 173,891	$ 1,163,297
IESO Communications Support	$ 742,730	$ 50,000	$ 51,500	$ 53,045	$ 54,636	$ 56,275	$ 57,964	$ 1,066,150
Total IESO Costs	$ 6,633,147	$ 6,632,714	$ 6,633,147	$ 6,104,422	$ 6,374,678	$ 6,565,919	$ 6,762,896	$ 47,693,055
Vendor Base Contract	$26,926,352	$12,375,954	$13,935,600	$13,935,600	$13,935,600	$13,935,600	$13,935,600	$ 108,980,306
Vendor Base Contract - PST	$ 1,204,645	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,204,645
Vendor Change Orders and Infrastructure Improvements	$ (813,192)	$ 2,612,307	$ 400,000	$ -	$ -	$ -	$ -	$ 2,199,115
Maintenance on Changes to the MDM/R	$ -	$ 149,955	$ 243,503	$ 262,190	$ 275,300	$ 289,065	$ 303,518	$ 1,523,531
LDC Testing Facilities	$ -	$ 837,500	$ 909,000	$ 936,270	$ 964,358	$ 993,289	$ 1,023,088	$ 5,663,504
Total Vendor Costs	$27,317,805	$15,975,716	$15,488,103	$15,134,060	$15,175,258	$15,217,954	$15,262,206	$ 119,571,101
Total Phase 3 Costs	$35,937,084	$22,608,429	$22,121,250	$21,238,482	$21,549,937	$21,783,873	$22,025,102	$ 167,264,156
Phase 4 (Accelerated TOU Rollout Plan & OEB Mandate)	$ 8,036,015	$ 960,793	$ -	$ -	$ -	$ -	$ -	$ 8,996,808
Release 7.2 and Measurement Canada 2011 Solution	$ 7,099,919	$ 2,965,337	$ -	$ -	$ -	$ -	$ -	$ 10,065,255
Measurement Canada 2012 Solution and Required Upgrades	83769	$ 6,804,146	$ 1,000,000	$ -	$ -	$ -	$ -	$ 7,887,915
SME Corporate Costs	$ 15,282	$ 100,000	$ -	$ -	$ -	$ -	$ -	$ 115,282
Provision for Changes to the MDM/R and Contingency	$ -	$ 0	$ 4,696,097	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 5,000,000	$ 24,696,097
SUB-TOTAL	$71,488,352	$33,438,705	$27,817,347	$26,238,482	$26,549,937	$26,783,873	$27,025,102	$ 239,341,798
Financing Costs	$ 2,312,559	$ 1,581,591	$ 1,980,930	$ 2,278,536	$ 2,216,336	$ 1,352,350	$ 456,241	$ 12,178,542
TOTAL	$73,800,911	$35,020,296	$29,798,277	$28,517,018	$28,766,273	$28,136,223	$27,481,343	$ 251,520,340

42. The total costs presented in the table above differ from the Ministry-approved budget of approximately $89 million. The Ministry-approved budget was premised on the basis of MDM/R design, delivery and an initial operation period through to only February 2012, as opposed to December 2017 (which corresponds to the asset life of the MDM/R). Actual costs for the SMSIP to February 2012 are $11.5 million under budget.

Phase 1 – MDM/R Procurement

43. Phase 1 covers costs for the period from inception of the SMSIP (July 2006) through to award of the delivery and operate contract to IBM Canada in December 2006.

44. Phase 1 is now complete. All costs were incurred in 2006.

45. The majority of the costs were for the IESO project team. Additional material costs were for legal services in negotiating the MDM/R contract and the services of the Independent Fairness Commissioner in overseeing and reporting on the execution of the competitive procurement process for the MDM/R.

Phase 2 – MDM/R Delivery

46. Phase 2 covers the development and delivery of the MDM/R functionality. Phase 2 was completed in 2010, with any remaining functionally transitioned to be implemented under Phase 3 through future releases and defect corrections.

47. The majority of Phase 2 costs are payments to IBM Canada for the development and delivery of the MDM/R functionality.

48. They also include payments for the IESO project team. These costs were partially offset by penalties for liquidated damages of approximately $1.5 million received to date from IBM Canada under the MDM/R Agreement in respect of delayed delivery.

Phase 3 - MDM/R Operations

49. Phase 3 is ongoing. It covers the period from the start of operation of the MDM/R (end of February, 2008) through to the end of December 2017 which represents the 10-year asset life of the MDM/R.

50. *IESO Project Team Costs:* Phase 3 includes the SME's costs to perform all of the services not performed by IBM in the operation of the MDM/R, including on-boarding and supporting LDCs, overseeing IBM, testing and implementing changes to the MDM/R, communications, training, managing the design, and all of the other required functions of the SME. Costs also include the incremental effort from IESO finance and settlement, legal and regulatory, information technology, human resources and other functional areas to support the operation of the MDM/R and the SME.

51. Forecast costs to support the SME and operate the MDM/R assume resource requirements of up to 15 full time equivalents ("FTEs") to operate the MDM/R and 5 to 7 contract and temporary resources for change initiatives and variable requirements.

52. The SME will be supported by up to 2 FTEs from IESO's mainstream business, primarily in the areas of finance, settlements, legal, regulatory, information technology and human resources, and this support work will be resourced through over-time, temporary resources or other means on a time and material basis.

53. *External Fees and Expenses:* Phase 3 includes forecast costs for the annual Section 5970 audits of the MDM/R, other computer services, software and equipment, LDC training, travel, telecommunications, external legal support, and staff expenses.

54. *Regulatory Process – Licensing & Cost Recovery*: This phase also includes a forecast for regulatory costs to cover IESO staff and external legal services for the SME license and rate applications.

55. *IESO Communications Support:* Phase 3 includes costs for the IESO's use of external communications consulting and the production of communications materials such as brochures to assist the Ministry of Energy in the education and promotion of smart meters and time-of-use rates to Ontario consumers. Phase 3 communications costs provide for the ongoing communications facilities, maintenance and update of communications content to support MDM/R service recipients in the operation, use, and governance of the MDM/R.

56. *Vendor Costs:* The bulk of these costs represent monthly fixed payments to IBM Canada under the operate portion of the MDM/R contract. The Phase 3 costs include actual and forecast payments to IBM Canada up until the end of March 2014. Vendor costs to operate the MDM/R for April 2014 to December 2017 have been forecast on the same basis.

57. *Vendor Change Orders and Infrastructure Improvements*: This item includes the cost of:

(a) changes to the MDM/R to support LDC integration and operation with the MDM/R;

(b) enhanced vendor support for LDC testing and implementation of changes to the MDM/R; and

(c) a provision for additional infrastructure to support functions added to the original contract.

58. These costs are partially offset by service level credits of $1,070,474 received to date from IBM Canada under the MDM/R Agreement in respect of the operation of the MDM/R.

59. *Maintenance on Changes to the MDM/R:* This item includes the maintenance costs for functions and services added to the original contract.

60. *LDC Testing Facilities*: Phase 3 includes costs for testing facilities to support LDC testing of changes to their systems or to the MDM/R. Experience to date has demonstrated the value of this in preventing issues impacting LDC billing.

61. *Release 7.2 and Measurement Canada 2011 Solution*: Measurement Canada has established requirements for reconciling consumption to the billing period beginning and ending cumulative register reads and presenting those register reads on the customer invoices. These requirements currently do not match the system capabilities of many LDCs. A solution was defined with an industry working group to address Measurement Canada's requirements and can accommodate all the Automated Meter Information Systems used in the

province. Measurement Canada's requirements will be substantially addressed in 2012 by implementation of a solution (known as the "Measurement Canada 2011 Solution") and Release 7.2 of the MDM/R system.

62. *Measurement Canada 2012 Solution and Required Upgrades:* The development and testing of software is underway to deliver the remaining elements of Measurement Canada's requirements (known as the "Measurement Canada 2012 Solution"). This solution is expected to be implemented in phases in 2012 and early 2013. Planning is also underway for upgrading the MDM/R's database management system from Oracle 10g, which is at end of life and nearing the end of support, to Oracle 11g. Forecast costs include estimates for software development and a project team to support the implementation of both initiatives.

63. *SME Corporate Costs* – These costs are related to the establishment of the MDM/R Co. and to support the transition of SME governance described in Exhibit B-2.

64. *Provision for Changes to the MDM/R and Contingency:* A contingency provision has been made for handling defects, corrections, small requests for change from LDCs, and maintenance of the MDM/R. No provision has been made for material changes to the MDM/R or its operation. The costs for making changes to the functions and operations of the MDM/R will be significantly influenced by government policy, LDCs and changes in the commercial arrangements with the contracted Operational Service Provider (post-March 2014) over the planning horizon.

Phase 4 – Accelerated Time-of-Use Rollout Plan

65. In 2009, the Ministry of Energy and Infrastructure requested that the SME produce a roadmap for the issuance of time-of-use bills across the province to meet government implementation targets. Pursuit of the roadmap was endorsed by the government, including the required additional support from the SME and vendors for the accelerated time-of-use rollout. Phase 4 was run concurrently with Phase 3.

66. Phase 4 was estimated to be $8 million and was funded through a government-approved $4 million increase to the SMSIP budget and $4 million re-allocation of contingency from Phase 2. Phase 4 costs arise from the required additional labour, contractor, vendor and hardware costs to support the accelerated roll-out of time-of-use rates across the province.

67. The Phase 4 costs now also include $550,000 to support the increased resources that are required to support LDC integration with the MDM/R in response to the subsequent establishment of a "mandatory TOU date" as outlined in section 1.2.1 of the OEB's Standard Supply Code.

Financing Costs

68. Debt financing for the SME is obtained through the IESO's note payable to the OEFC and IESO's corporate credit facility.

69. In May 2011, the IESO entered into a two-year note payable with the OEFC. The note payable is unsecured, bears interest at a fixed rate of 2.245% per

annum and is repayable in full on May 1, 2013. Interest accrues daily and is payable in arrears semi-annually in May and November of each year.

70. The IESO has an unsecured credit facility agreement with the OEFC, which will make available to the IESO an amount up to $110.0 million. Advances, up to $60.0 million, are payable at a variable interest rate equal to the Province of Ontario's cost of borrowing for a 30 day term plus 0.25% per annum, with repayments and interest payments due monthly. Advances, above $60.0 million and up to $110.0 million, are payable at a variable interest rate equal to the Province of Ontario's cost of borrowing for a 30 day term plus 0.50% per annum, with repayments and interest payments due monthly.

71. The IESO allocates an appropriate portion of the above note payable and credit facility costs to the SME.

Knowles

INDEPENDENT ELECTRICITY SYSTEM OPERATOR

REQUEST FOR PROPOSALS
FOR THE PROVISION AND OPERATION OF THE
METER DATA MANAGEMENT/REPOSITORY

FAIRNESS REVIEW

13 NOVEMBER 2006

Submitted by
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EXECUTIVE SUMMARY

This report presents our findings and conclusions as Fairness Commissioner for the Request for Proposals (RFP) process for the provision and operation of the Meter Data Management/Repository (MDM/R). The purpose of this RFP was to identify a Respondent to provide and operate the MDM/R for the province's Smart Metering initiative. This is the final report on the RFP process. We monitored and observed the process from issuance of the RFP up to, and including, the completion of the evaluation process. We were engaged by the Independent Electricity System Operator (IESO) in July 2006 and were involved in an advisory and oversight capacity during the finalization of the RFP document.

The IESO conducts procurement in a manner that stands the test of public scrutiny, encourages competition and reflects fairness in the spending of public funds. Competition among proponents is encouraged through open processes that afford vendors equal access to IESO procurement opportunities.

The Fairness Commissioner acts as a neutral, disinterested and independent monitor for the procurement process. We were not part of the RFP development or evaluation teams. We reported directly to the IESO Vice President responsible for the procurement.

The RFP was not written in an unduly restrictive manner. The evaluation criteria were objectively justified and the process for applying the criteria was clearly set out in the RFP. In addition, the evaluation process was described in sufficient detail so that it was transparent to Respondents.

The RFP was issued on September 7, 2006 and closed on October 5, 2006. Respondents had 21 business days (a day other than Saturday, Sunday or a Statutory Holiday) and 29 calendar days from the initial issuance of the RFP to the Submission Date.

The time that was allowed for Respondents to respond to the RFP was very aggressive. The timeline for the RFP was imposed on the IESO by the Smart Metering Initiative commitments. In our opinion, the time to respond to the RFP was sufficient because the IESO went through a pre-qualification process via an earlier Request for Information (RFI) to short-list only qualified Respondents, the IESO had already undertaken complete conceptual and logical designs for the MDM/R meaning that Respondents only had to map their solution physical design to the logical design in their Proposals, and the RFP was not changed significantly by any addenda that were released at issuance of the RFP. In addition to this, the

IESO had issued its MDM/RFI on July 27, 2006, some 43 calendar days before the issuance of the RFP, and this RFI document described the impending RFP opportunity. We also noted that MDM/R documents were available at the Ministry of Energy website and IESO www.smi-ieso.ca dedicated Smart Metering Initiative website ("Dedicated Website") in advance of the issuance of the RFP.

We are satisfied that the evaluation of the Proposals was conducted in accordance with the process set out in the RFP by applying only the rated criteria set out in Section 3 of the RFP. Furthermore, we detected no bias or favoritism towards or against any particular Respondent. The Base and Alternative Proposals were evaluated strictly against the rated evaluation criteria published in the RFP. A record of the consensus scoring reached and reasons for the scoring determinations was maintained and kept by the IESO for audit purposes.

In conclusion, based on our review, we are satisfied that the MDM/R RFP process was conducted in a procedurally fair, open, and transparent manner. We detected no bias either for or against any particular Respondent in the application of the evaluation criteria. The evaluation criteria published in the RFP were applied objectively to each Base or Alternative Proposal using the process set out in the RFP.

1.0 INTRODUCTION

This report presents our findings and conclusions as Fairness Commissioner for Request for Proposals (RFP) process for the provision and operation of the Meter Data Management/Repository (MDM/R). The purpose of this RFP was to identify a Respondent to provide and operate the MDM/R for the province's Smart Metering initiative. This is the final report on the RFP process. We monitored and observed the process from issuance of the RFP up to, and including, the completion of the evaluation process. We were engaged by the Independent Electricity System Operator (IESO) in July 2006 and were involved in an advisory and oversight capacity during the finalization of the RFP document.

Our report addresses the following aspects of the RFP process:

- Wording of the RFP document;
- Adequate communications to RFP Respondents;
- Adequate notification of changes in requirements;
- Confidentiality and security of proposals and evaluations;
- Qualifications of the evaluation team;
- Compliance with the process;
- Objectivity and diligence respecting the evaluations;
- Proper use of evaluation tools;
- Conflict of Interest; and,
- Debriefings.

The following sections in this report elaborate on these aspects of the RFP process. Capitalized terms in this report have the same meaning as capitalized terms in the RFP and are defined in Appendix A Definitions of the RFP.

This report is based on our observations of the RFP process and representations about the process made to Knowles Canada (Knowles) by the IESO. This report was prepared for the specific purposes of the IESO. Any other person that wishes to review this report must first obtain the written permission of the IESO and Knowles. Neither Knowles nor the individual authors of this report bear any liability whatsoever for opinions unauthorized persons may conclude from this report.

2.0 ROLE OF FAIRNESS COMMISSIONER

The IESO conducts procurement in a manner that stands the test of public scrutiny, encourages competition and reflects fairness in the spending of public funds. Competition among proponents is encouraged through open processes that afford vendors equal access to IESO procurement opportunities.

To provide the vendor community with the confidence that the procurement is conducted in a fair manner that is consistent with the above-mentioned principles, the IESO retained the services of a Fairness Commissioner to monitor the process and to advise on matters that pertain to the procedural fairness of the procurement process.

The Fairness Commissioner acts as a neutral, disinterested and independent monitor for the procurement process. We were not part of the RFP development or evaluation teams. We reported directly to the IESO Vice President responsible for the procurement.

3.0 BACKGROUND

The Government of Ontario has indicated that the pending retirement of coal plants and growth in the demand for electricity increases the urgency to create a conservation culture in the Province of Ontario and to make the Province a North American leader in energy efficiency. Key elements forming part of the Government's program to create a conservation culture include:

- The introduction of flexible, time-of-use ("TOU") pricing for electricity;
- A targeted reduction in Ontario's energy consumption by five percent by 2007; and
- A commitment to install a smart electricity meter in 800,000 homes by 2007 and in each and every home in Ontario by 2010.

Following consultations with stakeholders, the Ministry proceeded with a dual approach in the implementation of its Smart Metering Initiative, as follows:

1. *Decentralized Responsibilities (Local Distribution Companies ("LDCs")):*

   - Responsibility for purchasing, owning, installing, operating, and maintaining smart electricity meters as they are rolled out across the Province; and
   - Continued responsibility for the customer interface, including billing and access to smart meter information and data (together with third parties).

2. *Centralized Responsibilities:*

   - Overseeing the implementation of the Smart Metering Initiative;
   - Developing specifications and standards for all elements of the Smart Metering Initiative through a consultative process;
   - Developing the meter data management and meter data repository ("MDM/R") functions; and,
   - Designing and establishing a Smart Metering Entity.

On November 3, 2005, the *Energy Conservation Responsibility Act, 2005* was tabled in the Provincial legislature as Bill 21, for first reading and received Royal Assent on March 28, 2006 (S.O. 2006, Chapter 3).

This legislation will centralize MDM/R functions related to the collection, storage, management and transfer of consumers' consumption information and data within a Smart Metering Entity. The Bill also provides the framework for the regulation of the Smart Metering Entity, including licensing and approving or fixing just and reasonable rates.

In accordance with the Ontario Energy Board's regulated price plan, consumers will be required to purchase electricity under a rate structure featuring TOU prices. At some later date, an additional pricing structure for critical periods may also be introduced for those periods when the electricity system is at capacity and wholesale commodity prices are very high. Taken together, AMI with either TOU or critical peak pricing ("CPP") will enable consumers to receive timely information about their pattern and level of electricity consumption in a given time period and, in turn, their cost.

The smart metering system through which the Government will achieve its Smart Metering Initiative includes an AMI system and MDM/R functions. Only the MDM/R is the subject matter of this RFP.
The architecture of the province's Smart Metering Initiative is presented in Figure 1, below.

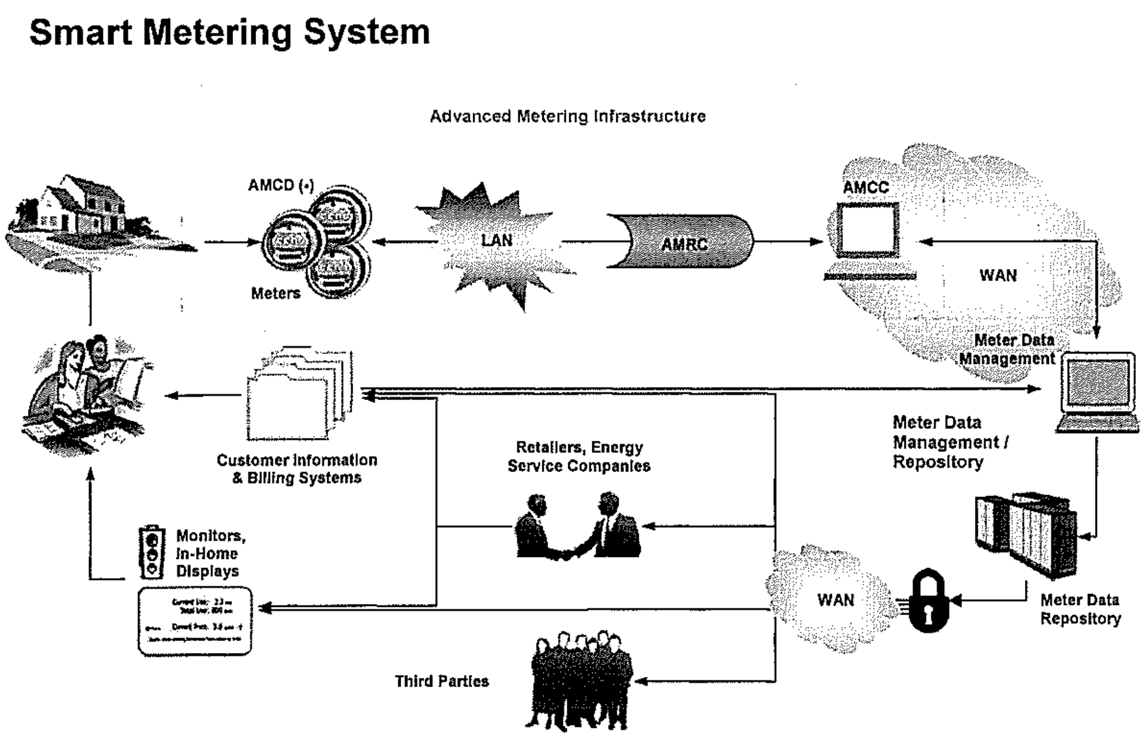

Figure 1 – Smart Metering System

Prior to the issuance of the RFP, the IESO conducted a Request for Information (RFI), which solicited information from the vendor community and requested that interested parties submit their qualifications to the IESO for short-listing for the RFP. As a result of the RFI, nine firms were short-listed for the RFP.

4.0 RFP Document

As Fairness Commissioner, our main task was to provide advice and oversight to the IESO, on ensuring a fair and transparent evaluation process. The RFP document had to accomplish three primary tasks:

1. Clearly identify and describe the nature of the opportunity;

2. Provide RFP Respondents with the information they needed to prepare a Proposal and allow them to price the opportunity; and

3. Describe the necessary and desirable qualifications for the successful Respondent and clearly set out these evaluation criteria and the process for applying them.

In achieving these objectives, the evaluation criteria had to be developed such that they were not biased for or against any particular Respondent and that undue advantage was not given to firms with previous experience with the IESO. The RFP requirements could not be so narrowly developed to unduly restrict participation in the competitive process. Sufficient response time and information had to be provided to permit those unfamiliar with the IESO and its procurement processes to prepare an Proposal.

We are satisfied that the RFP disclosed all the evaluation criteria used in the evaluation process, and provided an appropriate process for consistently and fairly evaluating Proposals. The RFP was not written in an unduly restrictive manner, and was not biased towards any particular Respondent.

Section 1 – Introduction of the RFP provided the necessary background information on the opportunity. More detailed background information was provided in RFP appendices: Appendix F – MRM/D Functional Specifications; Appendix G MDM/R Logical Application and Data Architecture; Appendix H MDM/R Business Process Description; and MDM/R Service and Performance Levels. The RFP clearly stated in s. 1.5 Who Should Use This Document, that only those Respondents that were pre-qualified under the RFI would be eligible to participate in the RFP.

Section 2 – Invitation to Bid, introduced the MDM/R functional specification (MDM/R Specifications) and MDM/R Deliverables. The Deliverables were itemized as Deliverable A, B, and C., as follows:

- Deliverable A - Work with the IESO and SMS stakeholders to finalize the MDM/R design and the specification of the interfaces surrounding the MDM/R;

- Deliverable B - The development, delivery, testing and placing into production of a turnkey solution to support the initial operation of the MDM/R according to the specified schedules, MDM/R Specifications and test criteria; and,

- Deliverable C - A service to operate the MDM/R for an initial period of 4 years according to the specified service levels; this will include contracting for all WAN services required to support the MDM/R interfaces.

In s. 2 of the RFP IESO also indicated that it required a turnkey solution, i.e. the provision of all hardware, software, licences, network infrastructure, WAN communications, environments, training services, design services, testing, as well as maintenance and support.

Section 3 – Instructions to Respondents, described the evaluation criteria and process for applying the criteria, and also the protocol for communications, Proposal submission instructions, the RFP timetable, and process for negotiating the final agreement. Section 3.8 set out the evaluation criteria. Respondents were instructed that their proposals would be initially screened for compliance with the RFP mandatory criteria. Respondents were instructed that their Proposals must comply with all the mandatory evaluation criteria in s. 5 of the RFP in order to have their Proposals evaluated further. Following the mandatory screening, those Proposals satisfying all mandatory criteria would be rated. There were five rated evaluation criteria:

1. Commitment to timelines for delivery (Evaluation Criterion #1);
2. Degree of conformance between the proposed solution and the MDM/R Specification (Evaluation Criterion #2);
3. Commitment to the long-terms needs of the operation of the MDM/R (Evaluation Criterion #3);
4. Solution flexibility and robustness (Evaluation Criterion #4); and,
5. Total Cost of Ownership (Evaluation Criterion #5).

The point allocation for each criterion was stated in the RFP and in our opinion the evaluation process was transparent to Respondents. Also, the evaluation criteria were objectively justified and evaluation process was clearly stated in the RFP.

At the conclusion of the evaluation process, the IESO reserved the right to enter into negotiations with any Respondent and to conclude a negotiated agreement based on the Commercial Terms in Appendix D of the RFP.

Section 4 – Proposal Format described the desired format for Proposals.

Section 5 – Mandatory Requirements, set out the mandatory requirements that a Proposal had to satisfy to be evaluated. These mandatory criteria were objectively stated, which allowed for an objective determination of compliance ("yes or no", "pass or fail", "comply or does not comply") to be made by the evaluators. Section 5.11 indicated that Respondents could submit Alternative Proposals. Respondents were required to submit a Base Proposal, which had to conform to all the RFP requirements, and could also elect to submit one or more Alternative Proposals in addition to their Base Proposal. An Alternative Proposal was a Proposal in which a Respondent could provide alternative aspects of the solution and/or pricing that would be different from the Base Proposal. Each Alternative Proposal was evaluated along side the Base Proposals using the same evaluation process. In this report we refer to both types of proposal as Proposals.

Section 6 – General and Technical Requirements elaborated further on the Deliverables that were set out in s. 2. The provision of the solution, delivery, installation, configuration, testing, and operation were all described.

Section 7 RFP Terms and Conditions set out the terms and conditions of the RFP process. In our experience, these terms and conditions were typical of other procurement processes with which we have been involved.

In summary, the RFP was not written in an unduly restrictive manner. The evaluation criteria were objectively justified and the process for applying the criteria was clearly set out in the RFP. In addition, the evaluation process was described in sufficient detail so that it was transparent to Respondents.

5.0 ADEQUATE TIME TO PREPARE A PROPOSAL

Respondents required sufficient time to prepare Submissions in response to the RFP. The larger the scope of the procurement and more complex it is, the longer the time that should be provided for Respondents so that they can understand the RFP requirements, assimilate the information in the RFP, conduct whatever research they deem necessary, and prepare a response to the RFP. The RFP timetable is presented in Table 1, below.

Table 1 - RFP Timetable

RFP Timetable	Dates & Times (EST)
Issue Date of RFP	September 7, 2006
Deadline for Receipt Confirmation Form	September 14, 2006 3:00pm
Initial Deadline for Submission of Questions	September 15, 2006 3:00pm
Extended Deadline for Submission of Additional Questions	September 21, 2006 12:00pm
Deadline for Issuing Addenda (includes answers to initial set of questions)	September 21, 2006 3:00pm
Deadline for Issuing Answers to Additional Questions	September 25, 2006 3:00pm
Closing Date/Time for RFP Submission	October 5, 2006 3:00pm
Recommendation to selection committee	November 6, 2006
If applicable, Selection Notice and Letter of Intent	November 27, 2006

The RFP was issued on September 7, 2006 and closed on October 5, 2006. Respondents had 21 business days (a day other than Saturday, Sunday or a Statutory Holiday) and 29 calendar days from the initial issuance of the RFP to the Submission Date.

The time that was allowed for Respondents to respond to the RFP was very aggressive. The timeline for the RFP was imposed on the IESO by the Smart Metering Initiative commitments. In our opinion, the time to respond to the RFP was sufficient because the IESO went through a pre-qualification process via the earlier RFI to short-list only qualified Respondents, the IESO had already undertaken complete conceptual and logical designs for the MDM/R, and the RFP was not changed significantly by any addenda that were released at issuance of the RFP. In addition to this, the IESO had issued its MDM/RFI on July 27, 2006, some 43 calendar days before the issuance of the RFP, and this RFI document described the impending RFP opportunity. We also noted that MDM/R documents were available at the Ministry of Energy website and IESO www.smi-ieso.ca dedicated Smart Metering Initiative website ("Dedicated Website") in advance of the issuance of the RFP.

6.0 ADEQUATE COMMUNICATION TO RESPONDENTS

It was important that all Respondents had timely access to the same and adequate information about the RFP and the associated process at the same time.

In s. 3.2 RFP Communications, Respondents were instructed to communicate only with the nominated IESO contact person before the RFP Submission Date. We are aware of no instances where RFP Respondents failed to comply with this instruction.

Appendices G through I of the RFP and other MDM/R-related documents were posted to the Dedicated Website to facilitate access by Respondents. The Dedicated Website went live in July 2006 and there were no reported service outages to date.

The IESO responded to a number of questions posed by Respondents. All questions received and answers given were sent to all pre-qualified Respondents. Information that might identify a Respondent was removed from the questions prior to issuance of the answers to all Respondents.

7.0 ADEQUATE NOTIFICATION OF CHANGES IN REQUIREMENTS

All Respondents received the same and adequate notification about changes to the RFP requirements.

There were three RFP Addenda issued. These addenda made minor modifications to the RFP documents and provided the questions posed and IESO answers to the questions. The addenda were shared with all Respondents.

We reviewed the RFP Addenda and question and answer documents prior to issuance and had no issues with content of these addenda.

8.0 CONFIDENTIALITY AND SECURITY OF DOCUMENTS

All Proposals and evaluation documents were kept strictly confidential and in secure locations. Documents relating to the RFP prior to issuance also had to be kept secure so that all Respondents had access to the same information at the same time.

During development of the RFP, draft versions of the document were only shared with those working on the document. We are aware of no departures from this practice.

Proposals and associated evaluation documents were kept in secure locations at all times. The Proposals were kept in a secure room at IESO offices. Evaluators were not permitted to remove Proposals from the IESO offices Evaluation documents were also stored in a secure location at IESO offices. All deliberations of the evaluation team were conducted behind closed doors at the same IESO offices.

We are not aware of any discussions about any Proposal or its evaluation among anyone except the evaluators, those supporting the evaluators, and us. To our knowledge, no information about the Proposals or evaluation was communicated in any form to persons not directly involved with the evaluation process.

We are satisfied that the contents of the Proposals and all information generated in the evaluation process was kept secure and confidential at all times.

9.0 QUALIFICATIONS OF THE EVALUATION TEAM

The evaluation team members had the appropriate knowledge and expertise to review and evaluate the Proposals. The evaluation team was composed of representatives of IESO and its external advisors, who had various degrees of expertise in smart metering and management of the data that the meters generated. Representatives of the Ministry of Energy observed various portions of the evaluation process, but did not participate in the evaluation and scoring of the Proposals. The evaluation team was divided into two sub-teams: a team evaluating Evaluation Criteria #1, #3 and #5, and another team evaluating Evaluation Criteria #2 and #4..

The evaluators all had relevant experience and qualifications in the area of metering data management. All evaluators had reviewed the RFP and familiarized themselves with the evaluation tools prior to commencing their evaluation of the Proposals

In summary, all the evaluators were qualified to undertake the evaluation of the Proposals and we have no concerns about the qualifications of any of the evaluators.

10.0 COMPLIANCE WITH THE PROCESS

In order to ensure a fair process, the procedures and process established for conducting the procurement, and published in the RFP, were followed and applied equally to all RFP Respondents. We are of the opinion that the evaluation process outlined in the RFP was complied with by the evaluators.

Seven of the nine pre-qualified Respondents submitted Proposals. One Respondent was disqualified because its Proposal did not satisfy all the mandatory requirements, and in fact the Respondent indicated in its Proposal that it was not compliant with all the mandatory requirements. Five Base Proposals and six Alternative Proposals were received from the six remaining Respondents.

After the mandatory requirements screening was completed the Base and Alternative Proposals were subjected to the rated evaluation criteria set out in Section 3 of the RFP. The Base Proposals were evaluated first, followed by the Alternative Proposal(s), for each Respondent. The two sub-teams of the evaluation team concurrently evaluated each Base and Alternative Proposal against the five rated evaluation criteria.

There was a minor departure from the staging of the evaluation of Total Cost of Ownership. Section 3.8 stated that the evaluation of the Total Cost of Ownership would occur after all the evaluation of the other four rated evaluation criteria was completed. One sub-team completed its evaluation of Evaluation Criteria #1 and #3 before the other sub-team had completed its evaluation of Evaluation Criteria #2 and #4. The IESO indicated to us that, given the time pressures of the Smart Metering Initiative, it would like to proceed with the evaluation of Evaluation Criterion #5, Total Cost of Ownership despite the fact that the other sub-team had not completed its rating of the Proposals. We indicated that the purpose of evaluation pricing last was so that knowledge of the pricing it did not influence the rated component of the evaluation process, which is to be evaluated on its technical merit alone. We advised the IESO that if it did decide to proceed with the evaluation of Total Cost of Ownership while the other sub-team was still doing its rated evaluation, it would have to sequester the pricing evaluation results and the evaluators could not be allowed to communicate with the other sub-team until it had completed its evaluation of the other rated criteria. The IESO accepted our advice, implemented it, and we are satisfied that the pricing information was not disclosed to the other sub-team until it had completed its rating of the Proposals. Consequently, the integrity of the process was maintained.

We are satisfied that the evaluation of the Proposals was conducted in accordance with the process set out in the RFP by applying only the rated criteria set out in Section 3 of the RFP.

11.0 OBJECTIVITY IN RESPECT OF THE EVALUATIONS

The Base and Alternative Proposals received were evaluated objectively and diligently. We attended all the consensus evaluation sessions and we are satisfied that there was no external pressure placed on the evaluation team with regard to the evaluation of any Base Proposal or Alternative Proposal. We are satisfied that all Proposals were objectively evaluated against the evaluation criteria published in the RFP.

We did not observe the mandatory requirements screening, which was done by the IESO procurement specialist. A separate financial team from the IESO evaluated the mandatory financial requirements. We did review the results of the mandatory requirements screening and from our review of the documents and interview with the evaluator conducting the mandatory requirements screening, we are of the opinion that only the mandatory requirements set out in s. 5 of the RFP were applied.

In conducting the rated criteria evaluation, each evaluator read the Base and Alternative Proposals individually and scored each Proposal individually. The two evaluation sub-teams met to conduct separate consensus scoring sessions, where consensus scores were arrived at for each criterion for each Base and Alternative Proposal. At these consensus scoring sessions the evaluators' individual scores were disclosed and the rationale for the scores was discussed and a consensus score was arrived at. In most instances the Base Proposal and Alternative Proposal rated criteria score were identical or very similar. The Ministry of Energy observers were present for some of the consensus evaluation meetings and they in no way attempted to influence the consensus evaluation process used by the evaluators.

We monitored the evaluation of Evaluation Criterion #5 Total Cost of Ownership (TCO). All the pricing for the Base and Alternative Proposals was complete and without any irregularities. One Alternative Proposal was not of interest to the IESO and it exercised its discretion set out in s. 5.11 to reject this Alternative Proposal. We noted that this Alternative Proposal also contained pricing in terms of a range of possible prices, so in any event the Alternative Proposal could not have been evaluated because it was not possible to determine its price. We checked the spreadsheets used in calculating the TCO and we are satisfied that TCO evaluation was done correctly.

In summary, we detected no bias or favoritism towards or against any particular Respondent. The Base and Alternative Proposals were evaluated strictly against the rated evaluation criteria published in the

RFP. A record of the consensus scoring reached and reasons for the scoring determinations was maintained and kept by the IESO.

12.0 Proper Use of Assessment Tools

Evaluation tools were used by the evaluators to evaluate the rated evaluation criteria. These tools took the form of worksheets which contained the evaluation criteria as well as a set of guidelines for allocating rated points, and a section where the evaluators could record their comments. We reviewed all the evaluation tools and we are satisfied that they accurately reflected the published rated evaluation criteria.

13.0 CONFLICT OF INTEREST

For the RFP process to be fair there had to be no conflict of interest between the evaluators and the Respondents and between the Respondents and anyone involved in planning or conducting the procurement. Respondents must also not have had access to confidential information as it pertains to the RFP.

The Respondents were required to disclose and declare any actual or potential conflict of interest. None of the Respondents declared that they were in a position of conflict of interest. Evaluation team members must also not be in a position of conflict of interest. The IESO informed us that none of the evaluators were in a position of actual or potential conflicts of interest.

14.0 Debriefings

As of the date of this report no debriefings have been held.

15.0 CONCLUSIONS

In summary, based on our review, we are satisfied that the MDM/R RFP process was conducted in a procedurally fair, open, and transparent manner. All Base and Alternative Proposals received were evaluated against the evaluation criteria published in the RFP. We detected no bias either for or against any particular Respondent in the application of the evaluation criteria. The evaluation criteria published in the RFP were applied objectively to each Base or Alternative Proposal using the process set out in the RFP.

B

SMC RATE STRUCTURE

72. The proposed rate structure for the SMC is a monthly charge per Residential and General Service <50kW Customer, which the SME proposes to collect from LDCs. Under the proposed approach, the SME's approved revenue requirement would conceptually be allocated to and recovered monthly from all of the province's LDCs on a "per customer" basis, regardless of whether an LDC is currently receiving service from the MDM/R.

73. The SME consulted with LDC representatives in determining that a "per customer" charge was the most appropriate rate structure. The proposal spreads the costs of the SME over the total number of smart meters expected to be deployed in recognition that the MDM/R provides a service that will benefit all end-use smart meter customers across Ontario and help meet the province's conservation goals.

74. The proposed rate structure is consistent with well-established criteria of a sound rate structure:[1]

(a) *Simplicity*: The proposed rate structure is simple to understand and administer because it uses reliable and accurate data on the number of Residential and General Service <50kW Customers for the province as a whole and each distributor. This will allow distributors to easily and accurately anticipate the SMC payable each year.

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[1] Charles F. Phillips, Jr., *The Regulation of Public Utilities, Theory and Practice*, 3rd ed. (Arlington, VA: Public Utilities Reports, Inc., 1993) at pp. 434 and 435.

(b) *Stability:* Application of the proposed rate structure will allow the SME to recover revenue requirements for its total costs. The proposed structure also provides for both revenue and rate stability and will help smooth the cash flow impact for the SME and reduce its forecast risk.

(c) *Fairness*: The majority of the SME's costs are common rather than direct (*i.e.* they are attributable to all MDM/R activities). The SME's capability to provide services is mainly achieved through staff and integrated information technology, and the bulk of the SME costs do not vary with the number of meters to which service is provided. The ongoing costs of the MDM/R do not depend on usage levels and the integrated nature of the MDM/R does not lend itself to a precise cost allocation based on MDM/R functions or the date on which service commences. Therefore, it is fair that the costs of the SME be shared equally amongst end use customers regardless of when that customer began receiving service. Substantially all of the LDCs and their meters have now been enrolled with the MDM/R and the majority of consumers are enabled for time-of-use billing.

(d) *Efficiency*: Spreading cost recovery over all Residential and General Service <50kW Customers regardless of the actual date on which service commences ensures there is no disincentive for an LDC to begin using the services of the MDM/R as soon as possible. By contrast, if the SME were to charge the SMC per smart meter registered with and transmitting data to the MDM/R, the resulting fee would impose an undue burden on those distributors (and their ratepayers) that are early adopters. The proposed approach is responsive to the concerns expressed by LDCs and is consistent with the Board's allowance of a preliminary smart metering rate adder to provide initial funding for smart meter investment and help smooth the cash flow impacts for distributors in its 2006 EB-2005-0529 Decision.

75. In devising the proposed rate structure, the SME considered and rejected other options:

(a) *Fixed user charge*: The SME determined that a fixed user charge (*i.e.* a "per LDC" charge) would not be appropriate in these circumstances. As LDCs will be seeking to pass the SMC onto end-use customers, a fixed rate would unfairly burden the customers of smaller LDCs by requiring them to pay more than the customers of large LDCs. By contrast, using a rate that varies with the number of customers for all LDCs provides a level playing field for the end-use customer that is transparent and non-discriminatory. Under this approach, all LDCs and their customers will be treated equally and will pay the same per unit charge for using the MDM/R system.

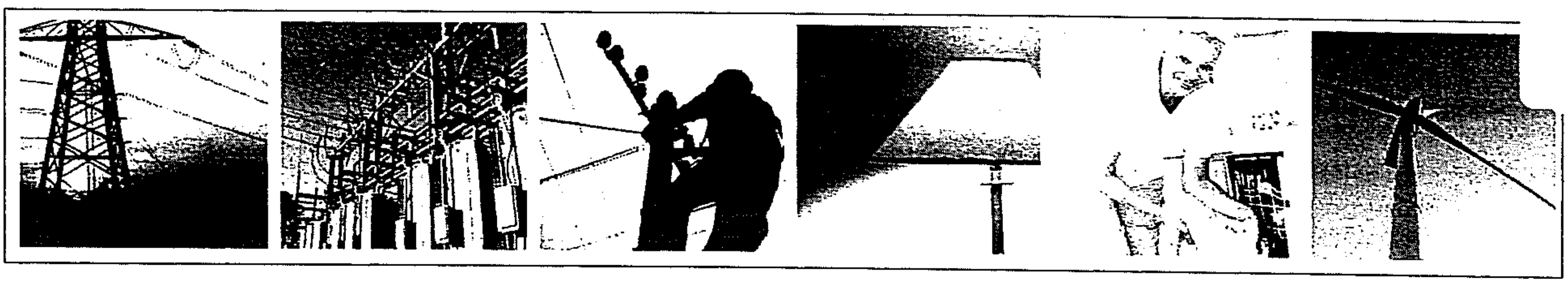
(b) *Volumetric Charge:* The SME also rejected the option of using a volumetric charge. The costs of the SME are not related to the volume of energy used by consumers and a volumetric charge is less stable and predictable than a per customer charge.

Ontario Energy Board
Commission de l'énergie de l'Ontario

2010 Yearbook of Electricity Distributors

Ontario Energy Board

Published on August 29, 2011



Background on 2010 Statistical Yearbook of Electricity Distributors

The Ontario Energy Board is the regulator of Ontario's natural gas and electricity industries. In the electricity sector, the Board sets transmission and distribution rates, and approves the Independent Electricity System Operator's (IESO) and Ontario Power Authority's (OPA) budgets and fees. The Board also sets the rate for the Standard Supply Service for distribution utilities that supply electricity (commodity) directly to consumers.

The Board provides this 2010 Yearbook of Electricity Distributors to inform interested parties and the general public with financial and operational information collected from Electricity Distributors. It is compiled from data submitted by the Distributors through the Reporting and Record-Keeping Requirements. Hydro One Remote Communities and direct connections to the transmission grid are not presented. This yearbook is also available electronically on the OEB website.

Table of Contents

*The following distributors have not filed RRR information for 2010: Attawapiskat First Nation, Fort Albany First Nation and Kashechewan First Nation.

NOTES

Financial Statement Disclosures

1. Balance sheet and income statement disclosures reflect the utilities' audited financial statements.

2. As a result of changes in disclosure in 2010, year-over-year comparisons and trending may be affected.

3. Debit balances reported in credit fields were reclassified to assets; and credit balances in debit fields were reclassified to liabilities.

4. In 2010, more debt is disclosed as long-term and has been classified between third party debt and debt with related, associated or affiliated parties.

5. Regulatory assets and liabilities are netted together and classified as regulatory assets or liabilities (net) depending on sign.

6. Future income tax assets and liabilities may have been classified by utilities as regulatory assets or liabilities in their filings with the Board. Wherever possible, this has been classified in the yearbook as other non-current assets or future income tax liabilities depending on sign.

Statistical

7. Loss of Supply Adjusted Service Reliability Indices are published under the Unitized Statistics and Service Quality Requirements tab.

8. Total customer figure is the sum of residential, GS<50, GS>50 (includes intermediate), large user and sub transmission rate classes. Unmetered scattered load connections are not included in the customer count.

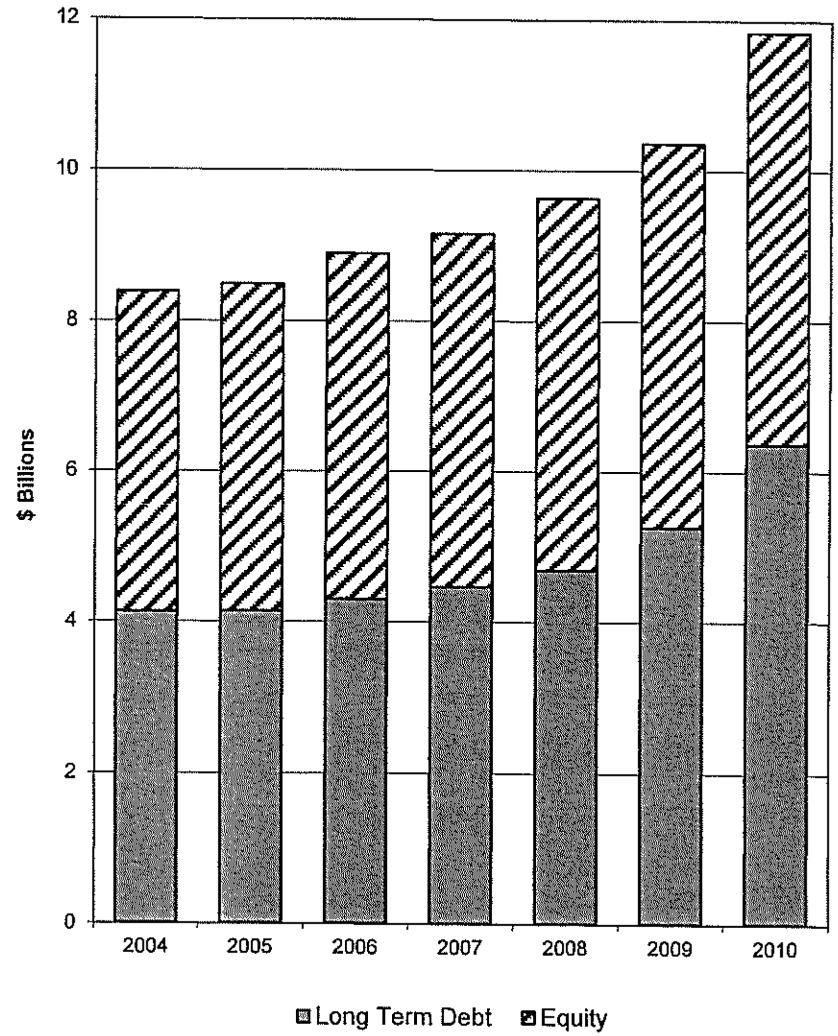
9. OEB minimum standards for Service Quality Requirements are published.

Overview of Ontario Electricity Distributors

Balance Sheet

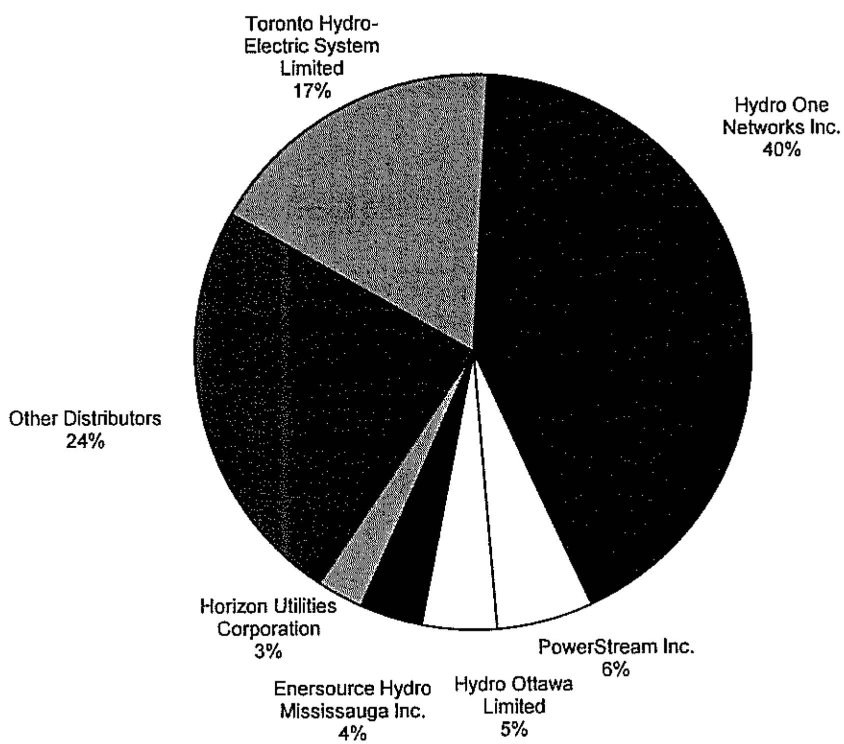
	As of December 31, 2010
Cash & cash equivalents	$ 505,266,250
Receivables	2,534,705,499
Inventory	89,084,349
Inter-company receivables	68,479,172
Other current assets	77,940,468
Current assets	3,275,475,738
Property plant & equipment	21,870,246,751
Accumulated depreciation & amortization	(9,652,762,713)
	12,217,484,039
Regulatory assets (net)	318,429,185
Inter-company investments	1,204,613
Other non-current assets	404,935,718
Total Assets	$ 16,217,529,293
Accounts payable & accrued charges	1,820,695,420
Future income tax liabilities - Current	18,704,068
Other current liabilities	125,790,383
Inter-company payables	438,441,369
Loans, notes payable, current portion long term debt	352,716,960
Current liabilities	2,756,348,200
Long-term debt	907,204,048
Inter-company long-term debt & advances	5,465,819,020
Regulatory liabilities (net)	94,429,066
Other deferred amounts & customer deposits	445,063,290
Employee future benefits	897,019,708
Future income tax liabilities	184,337,432
Total Liabilities	10,750,220,765
Shareholders' Equity	5,467,308,527
Total Liabilities & Equity	$ 16,217,529,293

Long-Term Debt & Equity

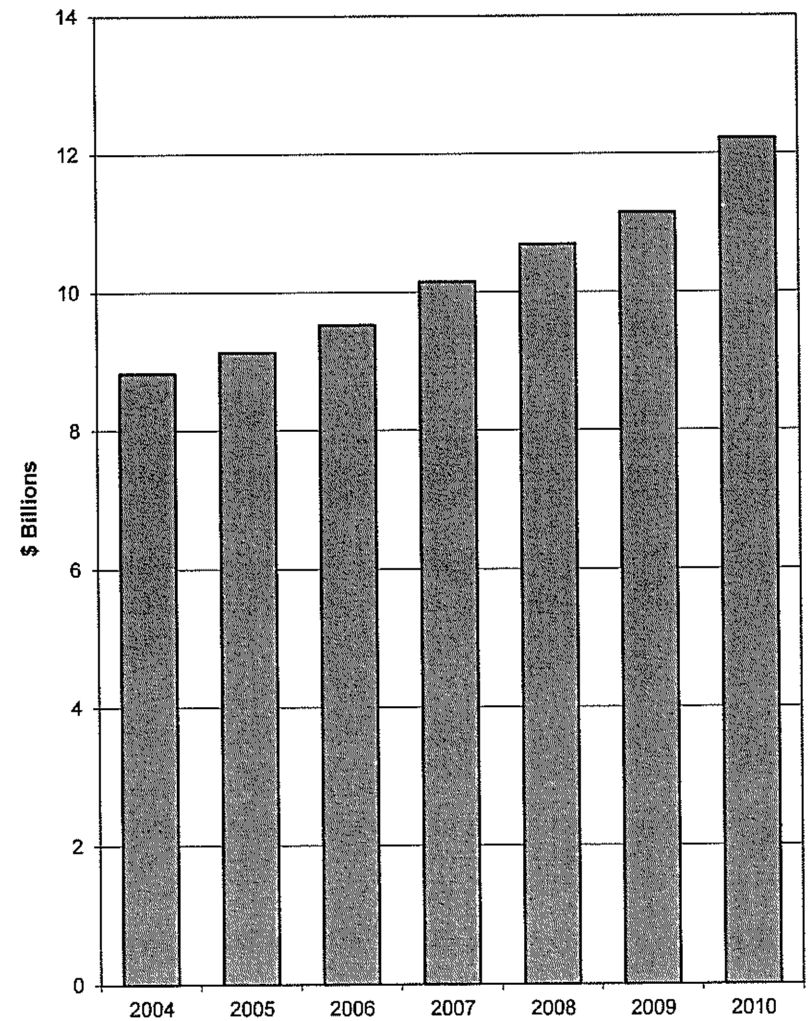


See notes 1, 2, 4

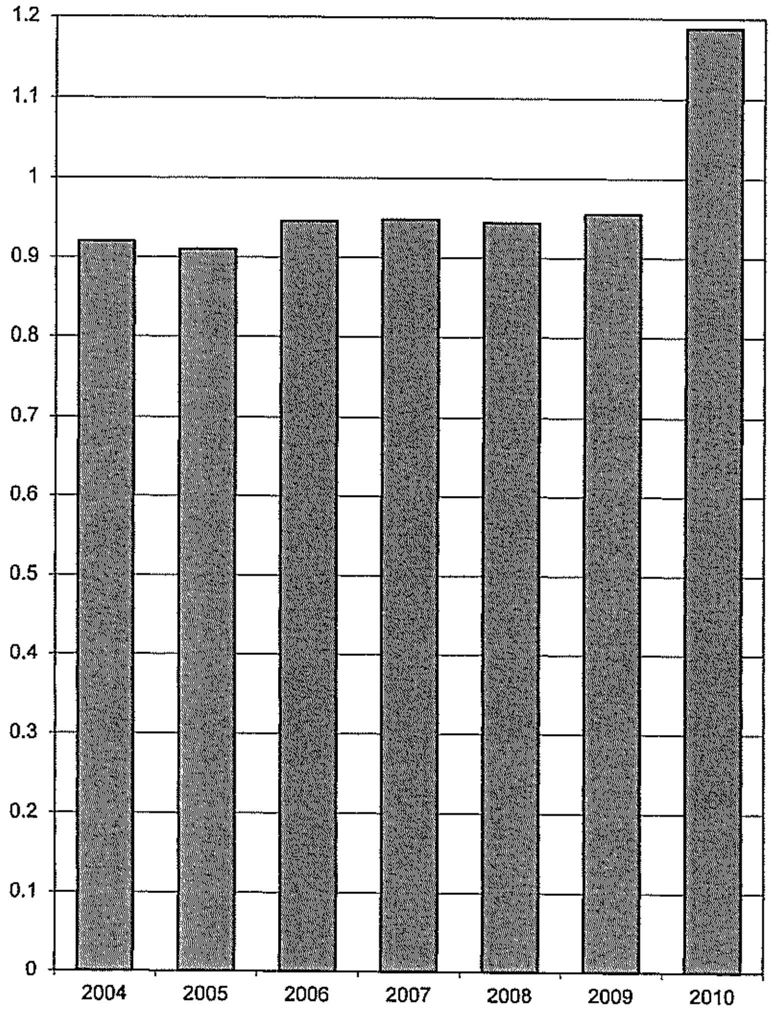
Net Property Plant & Equipment by Distributor
$12.2 billion



Net Property Plant & Equipment

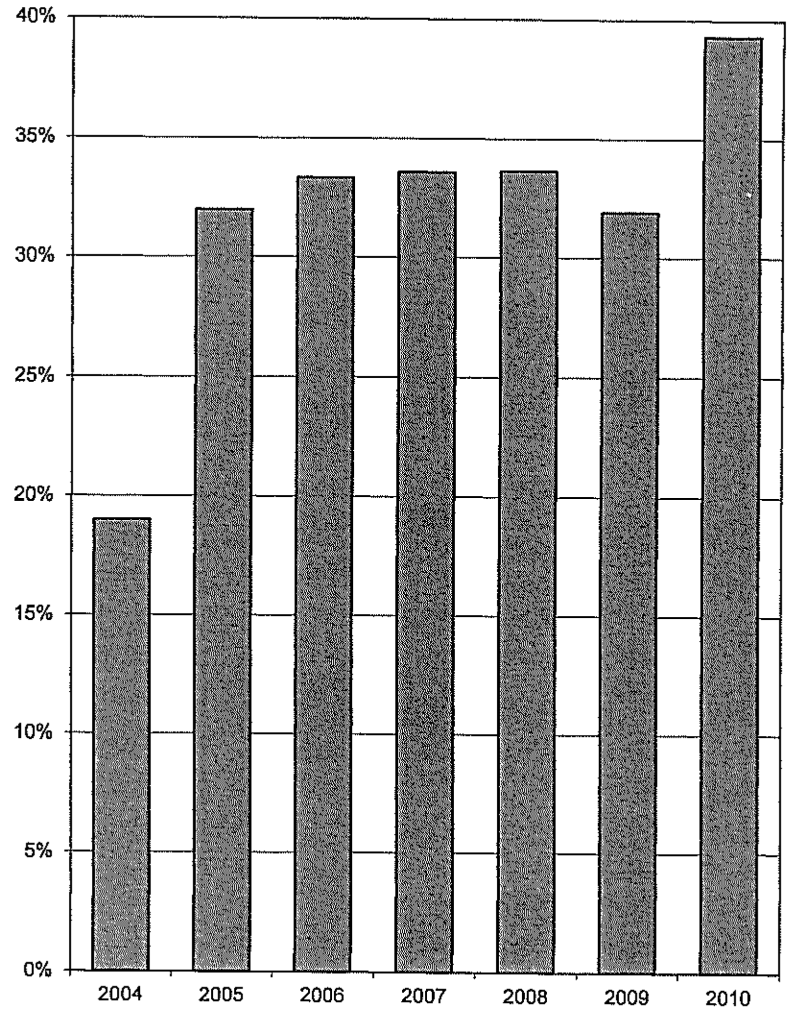


Current Ratio (Current Assets / Current Liabilites)



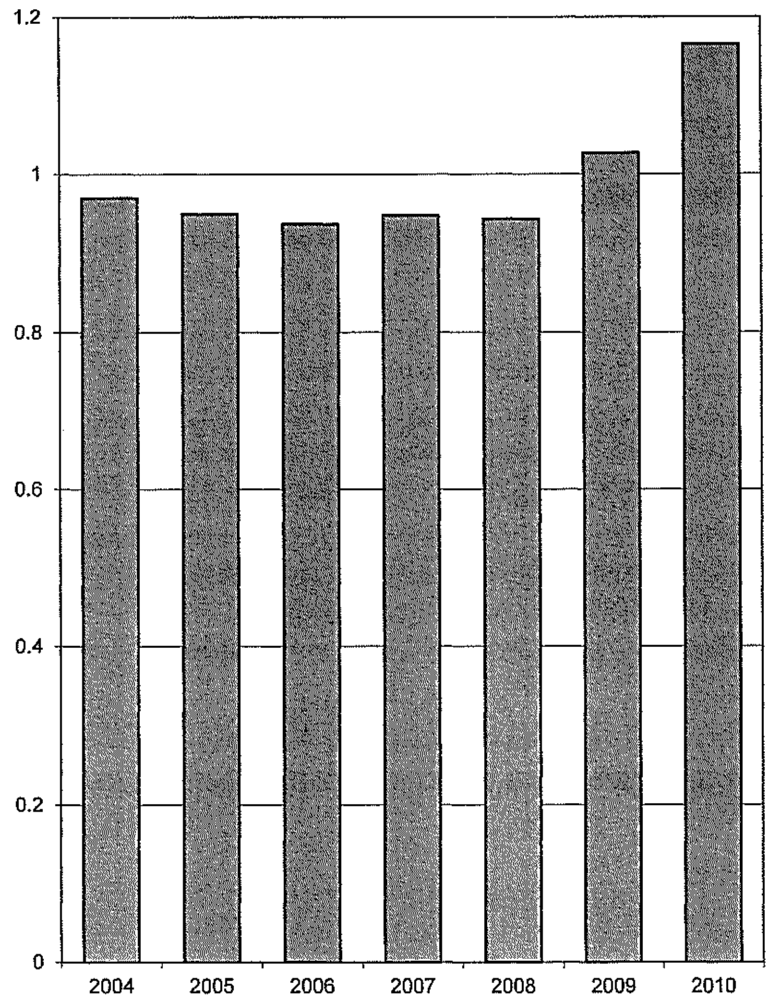
See notes 1, 2, 3, 4, 6

Debt Ratio (Long-Term Debt / Total Assets)



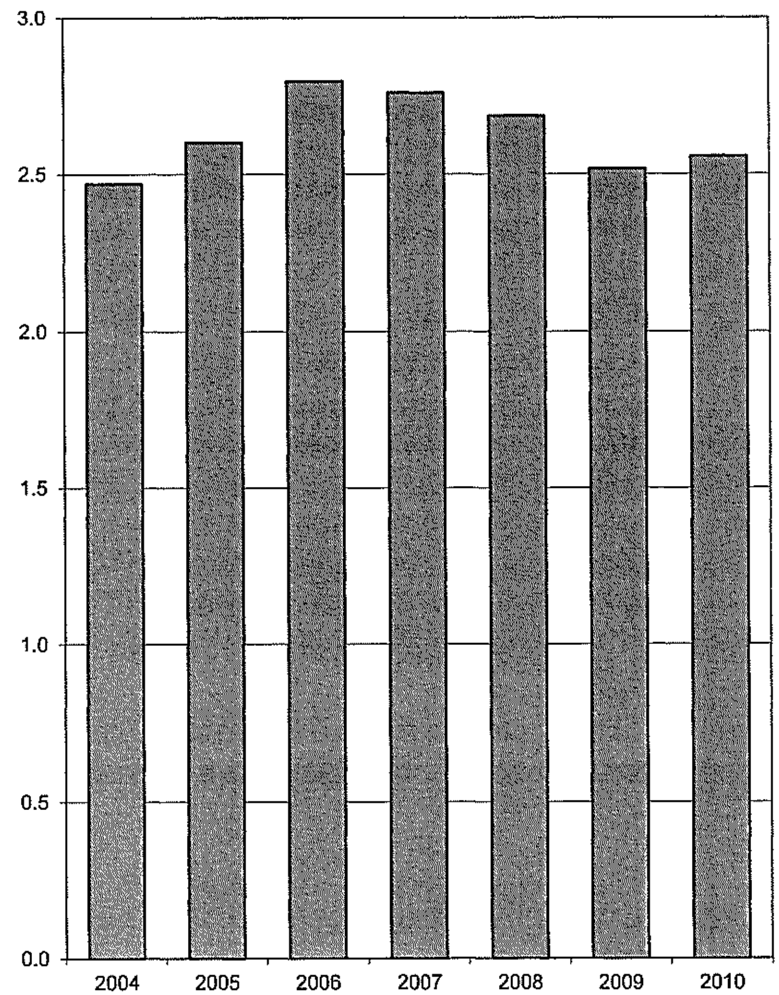
See notes 1, 2, 4

Debt to Equity Ratio
(Long-Term Debt / Equity)



See notes 1, 2, 4

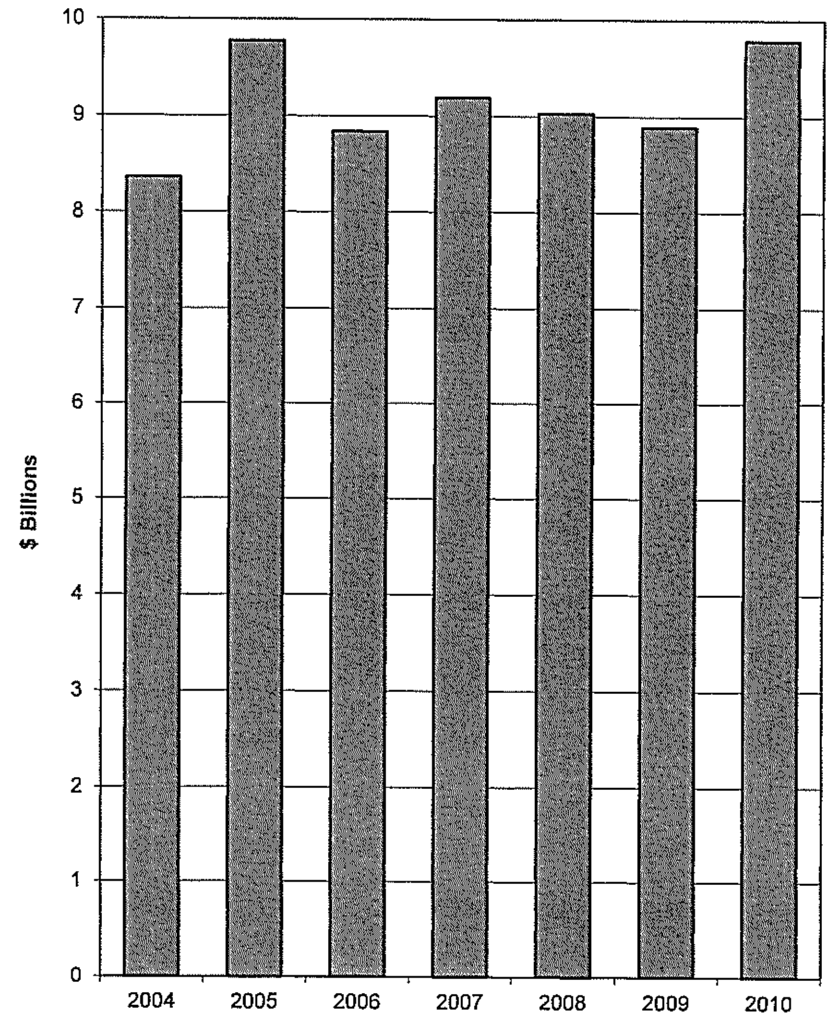
Interest Coverage
(EBIT / Interest Charges)



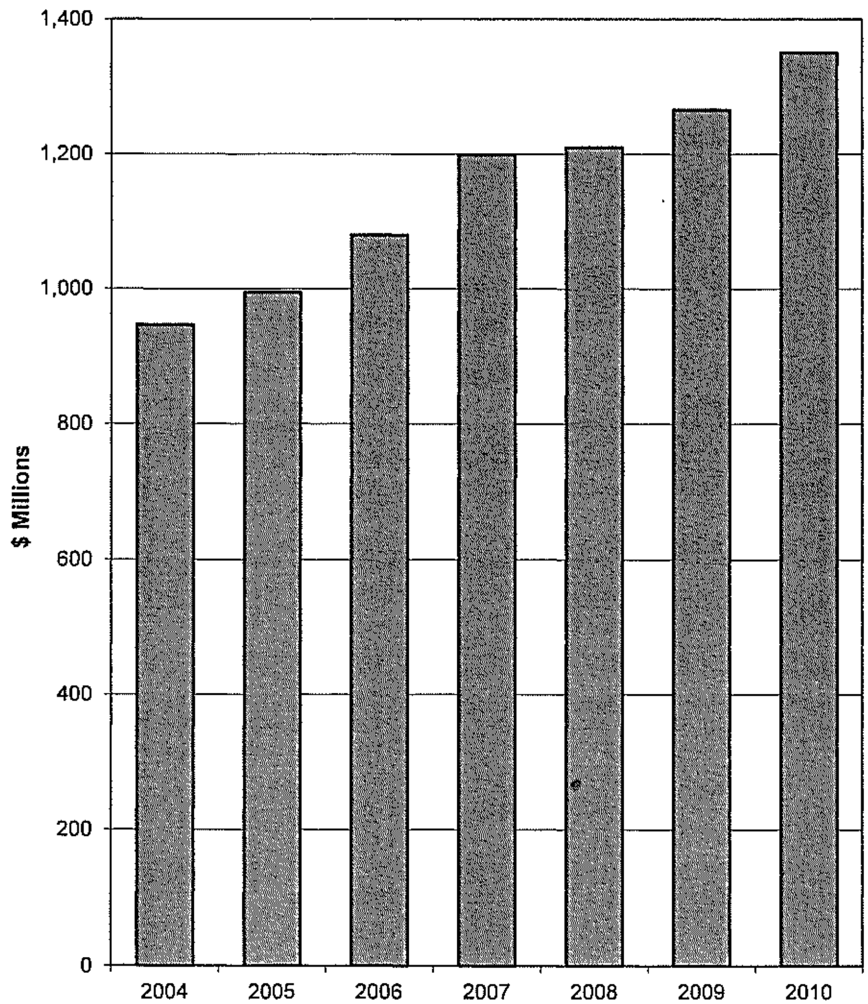
Overview of Ontario Electricity Distributors

Income Statement	Year ended December 31, 2010
Revenue	
Power & Distribution Revenue	$ 12,839,252,356
Cost of Power & Related Costs	9,786,532,663
	3,052,719,693
Other Income	90,923,551
Expenses	
Operating	258,866,440
Maintenance	373,860,732
Administration	717,915,492
Other	38,586,212
Depreciation and Amortization	804,634,237
Financing	371,411,032
	2,565,274,145
Net Income Before Taxes	578,369,100
PILS and Income Taxes	
Current	105,448,578
Future	814,261
	106,262,839
Net Income	$ 472,106,260

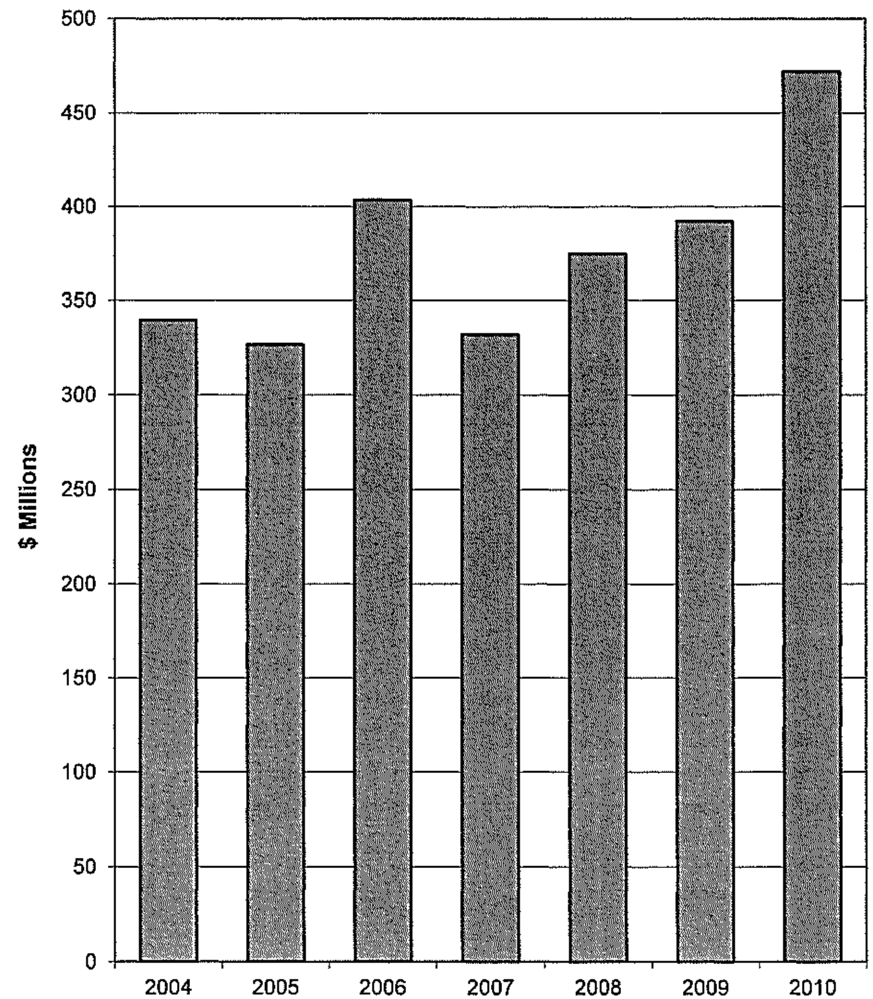
Cost of Power



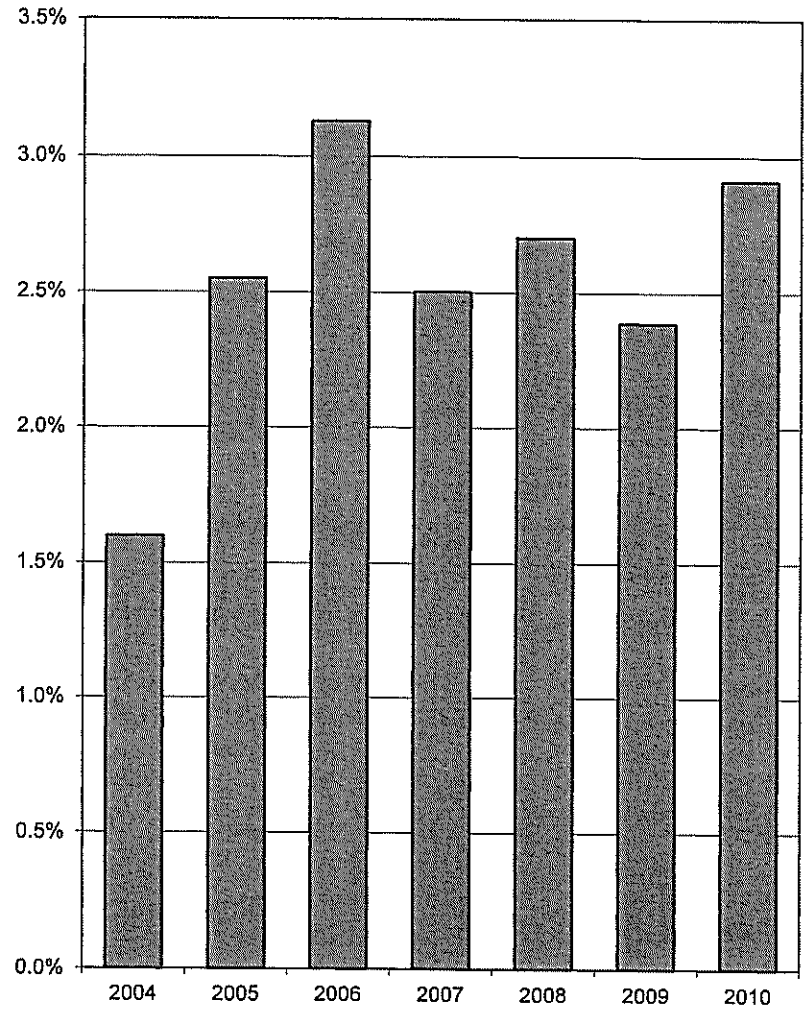
Operating, Maintenance & Administrative Expenses



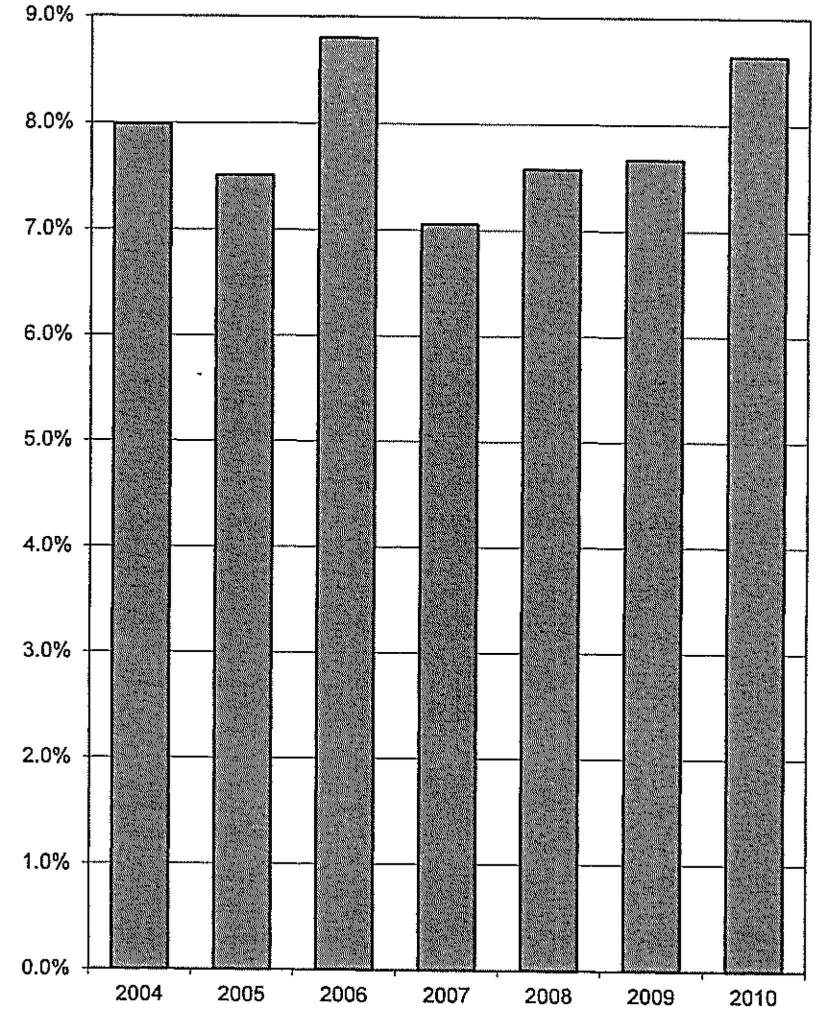
Net Income



Financial Statement Return on Assets
(Net Income / Total Assets)



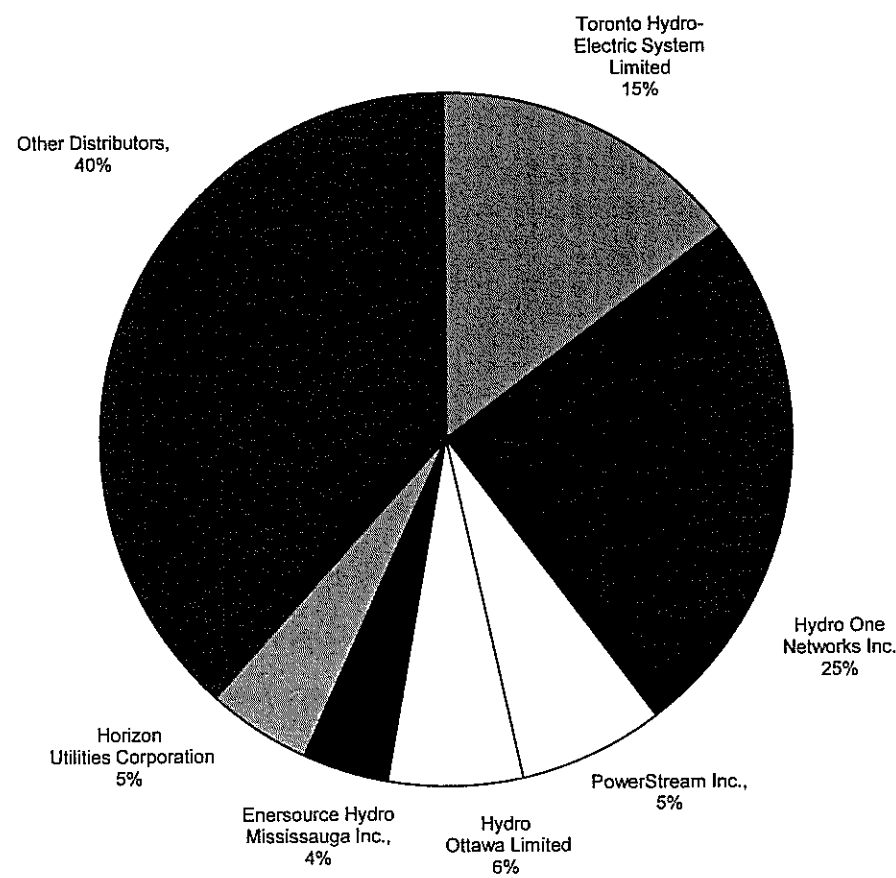
Financial Statement Return on Equity
(Net Income / Shareholder's Equity)



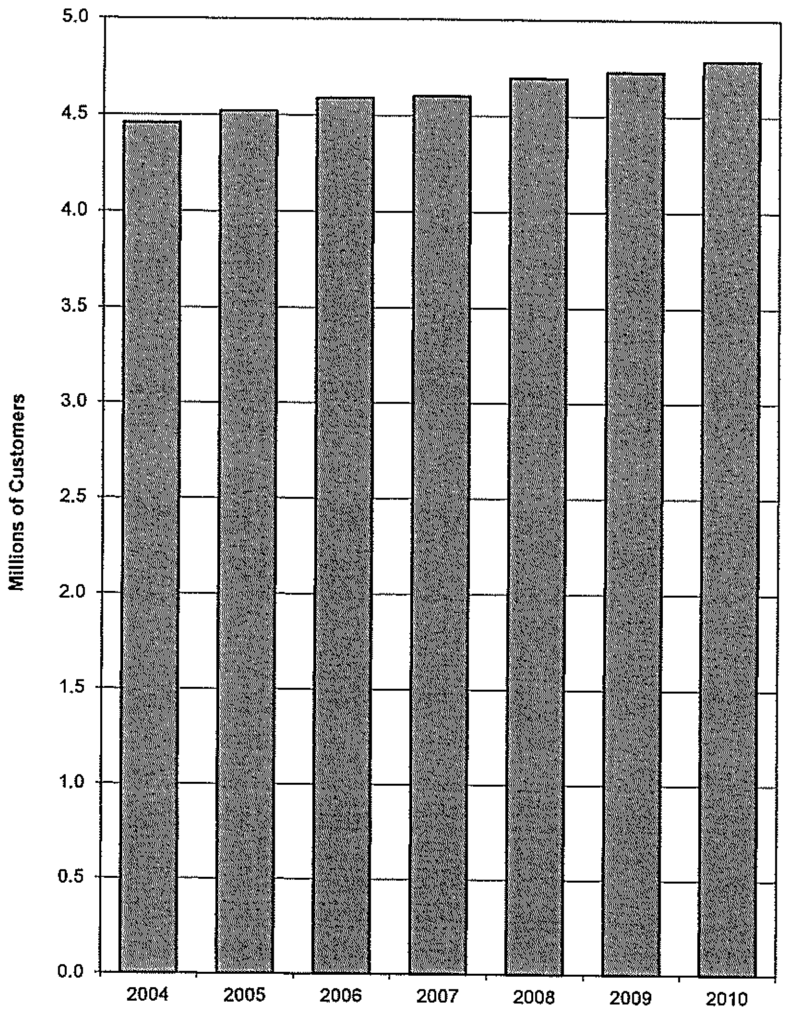
Overview of Ontario Electricity Distributors

GENERAL STATISTICS		Year ended December 31, 2010
Population Served		**13,618,469**
Municipal		14,323,424
Seasonal		165,459
Total Customers		**4,788,667**
Residential Customers		4,314,896
General Service <50kW Customers		415,994
General Service (50-4999kW) Customers		57,210
Large User (>5000kW) Customers		145
Sub Transmission		422
Total Service Area (sq km)		**681,680**
% Rural		99%
% Urban		1%
Total km of Line		**197,588**
Overhead km of line		158,951
Underground km of line		38,637
Total kWh Purchased		**126,434,515,965**
Total kWh Delivered (excluding losses)		121,191,511,801
Total Distribution Losses (kWh)		5,243,004,164
Capital Additions in 2010	**$**	**1,804,926,943**
UNITIZED STATISTICS		
# of Customers per sq km of Service Area		7.02
# of Customers per km of Line		24.24
Average Power & Distribution Revenue less Cost of Power & Related Costs		
Per Customer annually	$	637.49
Per Total kWh Purchased	$	0.024
Annual Average Cost of Power		
Per Customer	$	2,044
Per total kWh Purchased	$	0.077
Average monthly total kWh consumed per customer		2,200
OM&A per customer	$	282
Net Income per customer	$	**99**
Net Fixed Assets per customer	$	2,551

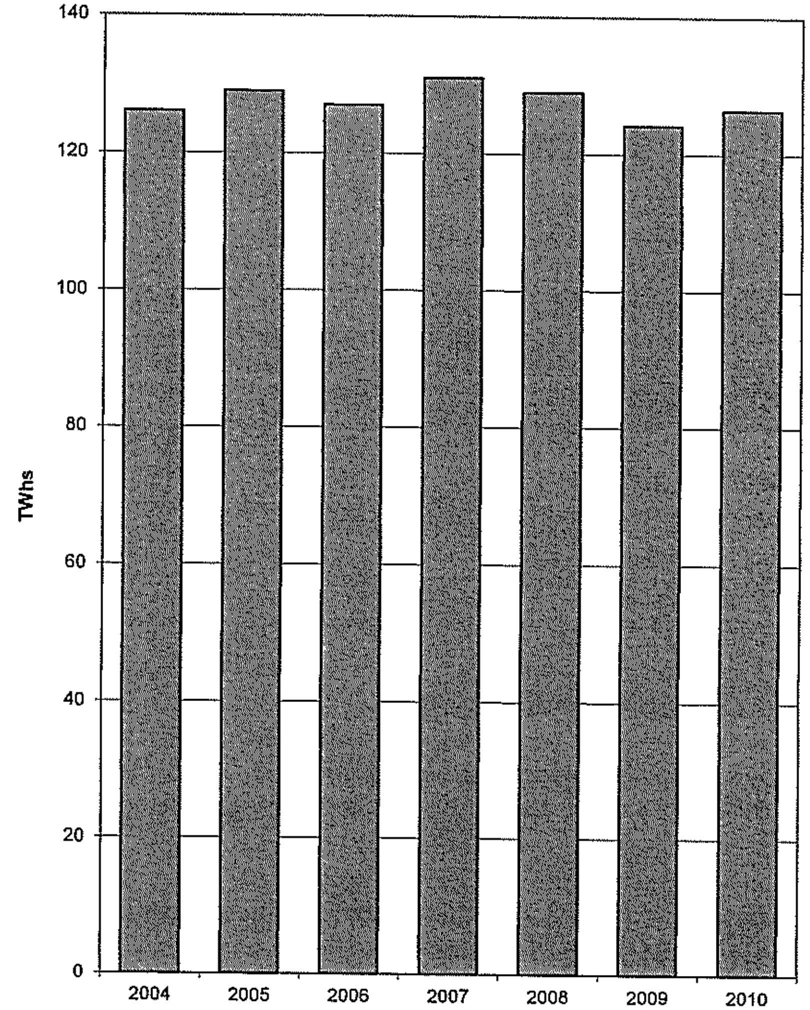
Percentage of Distribution Customers



Total Number of Customers



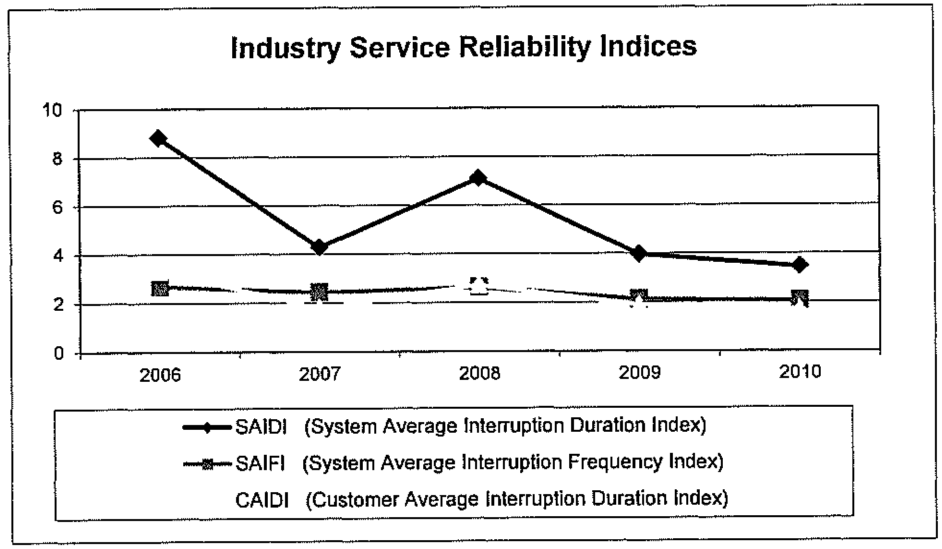
Total TWhs Purchased from IESO



Service Reliability Indices

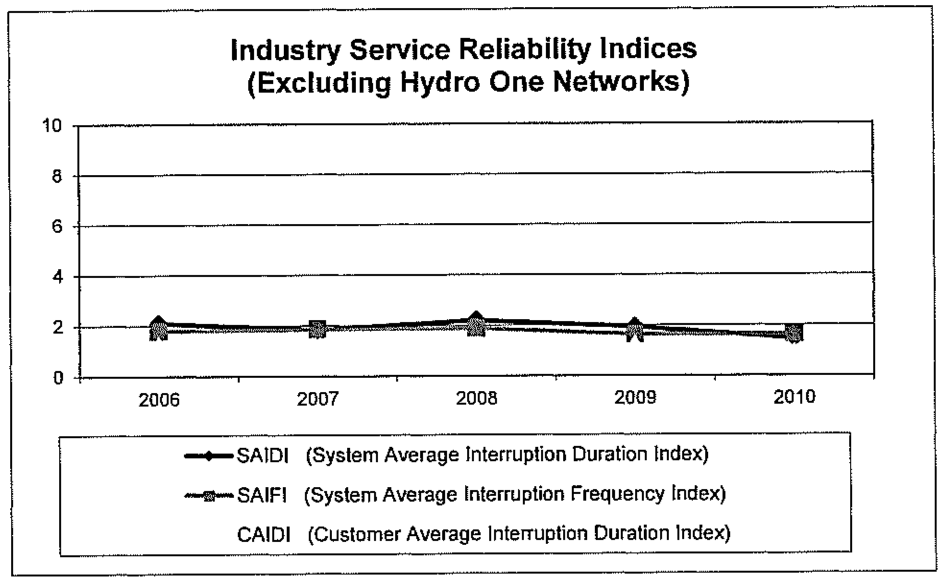
Industry

	2006	2007	2008	2009	2010
SAIDI	8.8	4.27	7.1	3.96	3.44
SAIFI	2.66	2.42	2.62	2.11	2.04
CAIDI	3.31	1.77	2.71	1.87	1.69



Industry Excluding Hydro One Networks

	2006	2007	2008	2009	2010
SAIDI	2.09	1.83	2.19	1.93	1.46
SAIFI	1.79	1.85	1.88	1.62	1.63
CAIDI	1.16	0.99	1.16	1.19	0.89



Note: Outage statistics report all outages affecting customers including those arising from within the distributor service area and those arising upstream from the distributor.

Balance Sheet As of December 31, 2010	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brant County Power Inc.	Brantford Power Inc.	Burlington Hydro Inc.
Cash & cash equivalents	$ 2,448,891	$ 89,748	$ 4,514,034	$ 1,494,586	$ 12,236,943	$ 15,452,262
Receivables	7,023,792	590,048	21,484,600	6,322,537	17,479,092	34,821,880
Inventory	127,516	108,062	596,509	277,034	1,613,545	1,130,332
Inter-company receivables	-	-	1,191,170	-	-	18,185
Other current assets	245,065	54,294	575,847	319,859	462,190	469,976
Current assets	9,845,264	842,151	28,362,160	8,414,015	31,791,770	51,892,635
Property plant & equipment	118,631,700	5,174,611	103,382,835	29,186,785	88,769,538	204,312,627
Accumulated depreciation & amortization	(48,181,771)	(2,936,880)	(60,859,607)	(9,588,672)	(26,709,019)	(119,192,445)
	70,449,929	2,237,731	42,523,228	19,598,113	62,060,520	85,120,183
Regulatory assets (net)	7,138,681	615,835	5,177,331	1,181,708	-	6,713,095
Inter-company investments	-	-	-	545,011	-	-
Other non-current assets	2,941,374	75,522	-	-	4,210,318	5,272,569
Total Assets	$ 90,375,248	$ 3,771,239	$ 76,062,719	$ 29,738,848	$ 98,062,608	$ 148,998,482
Accounts payable & accrued charges	$ 3,403,443	$ 448,610	$ 15,893,311	$ 4,896,950	$ 11,314,904	$ 25,984,532
Future income tax liabilities - current	-	-	-	-	-	-
Other current liabilities	645,833	-	470,729	69,765	9,936	501,709
Inter-company payables	381,643	-	2,288,117	12,200	1,745,173	-
Loans and notes payable, and current portion of long term debt	-	-	-	-	2,762,127	7,500,000
Current liabilities	4,430,919	448,610	18,652,157	4,978,915	15,832,139	33,986,241
Long-term debt	-	1,816,053	5,651,531	7,000,000	16,616,643	-
Inter-company long-term debt & advances	50,000,000	400,000	19,377,604	-	24,189,168	47,878,608
Regulatory liabilities (net)	-	-	-	-	5,496,452	-
Other deferred amounts & customer deposits	292,709	102,898	1,937,771	155,713	1,528,551	4,879,615
Employee future benefits	1,664,834	-	7,079,641	666,776	817,515	2,988,066
Future income tax liabilities	-	-	-	-	-	-
Total Liabilities	56,388,463	2,767,560	52,698,704	12,801,404	64,480,469	89,732,530
Shareholders' Equity	33,986,785	1,003,678	23,364,015	16,937,444	33,582,139	59,265,953
LIABILITIES & SHAREHOLDERS' EQUITY	$ 90,375,248	$ 3,771,239	$ 76,062,719	$ 29,738,848	$ 98,062,608	$ 148,998,482

Balance Sheet As of December 31, 2010	Cambridge and North Dumfries Hydro Inc.	Canadian Niagara Power Inc.	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	Chatham-Kent Hydro Inc.	Clinton Power Corporation
Cash & cash equivalents	$ 22,569,858	$ 3,701,153	$ 3,573,347	$ 426,052	$ 5,322,259	$ -
Receivables	20,529,368	6,712,427	3,485,714	638,592	13,160,098	1,430,684
Inventory	1,366,167	103,479	235,918	46,011	618,109	10,149
Inter-company receivables	-	-	-	-	581,849	13,794
Other current assets	416,596	364,246	110,981	2,648	488,212	136,376
Current assets	44,881,989	10,881,304	7,405,960	1,113,302	20,170,527	1,591,004
Property plant & equipment	168,139,327	87,136,399	15,675,786	2,244,665	81,249,611	2,148,816
Accumulated depreciation & amortization	(84,779,399)	(35,827,734)	(9,169,807)	(1,426,415)	(32,819,464)	(561,227)
	83,359,928	51,308,665	6,505,980	818,250	48,430,147	1,587,589
Regulatory assets (net)	5,670,951	3,174,871	-	227,724	3,573,112	322,142
Inter-company investments	-	-	-	-	-	-
Other non-current assets	4,343,662	4,314,670	867,842	-	-	-
Total Assets	$ 138,256,530	$ 69,679,511	$ 14,779,781	$ 2,159,276	$ 72,173,786	$ 3,500,734
Accounts payable & accrued charges	$ 18,229,028	$ 7,250,788	$ 1,945,831	$ 403,412	$ 11,249,776	$ 1,392,617
Future income tax liabilities - current	-	335,071	-	-	-	-
Other current liabilities	528,040	257,404	45,601	194	37,649	-
Inter-company payables	31,666	6,273,659	-	25,099	3,108,137	1,350,885
Loans and notes payable, and current portion of long term debt	-	-	-	-	-	210,014
Current liabilities	18,788,734	14,116,922	1,991,433	428,705	14,395,562	2,953,517
Long-term debt	35,000,000	16,050,000	5,046,753	-	-	-
Inter-company long-term debt & advances	6,684,703	20,000,000	-	-	31,273,326	-
Regulatory liabilities (net)	-	-	107,146	-	-	-
Other deferred amounts & customer deposits	12,149,380	-	951,463	24,144	1,701,860	54,754
Employee future benefits	2,009,355	4,169,600	125,006	-	954,707	-
Future income tax liabilities	-	1,869,261	-	-	-	-
Total Liabilities	74,632,172	56,205,783	8,221,801	452,849	48,325,454	3,008,271
Shareholders' Equity	63,624,358	13,473,728	6,557,980	1,706,428	23,848,332	492,464
LIABILITIES & SHAREHOLDERS' EQUITY	$ 138,256,530	$ 69,679,511	$ 14,779,781	$ 2,159,276	$ 72,173,786	$ 3,500,734

Balance Sheet As of December 31, 2010	COLLUS Power Corporation	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Enersource Hydro Mississauga Inc.	EnWin Utilities Ltd.	Erie Thames Powerlines Corporation
Cash & cash equivalents	$ 2,922,832	$ 1,568,858	$ 4,897,651	$ 29,392,913	$ 7,077	$ -
Receivables	7,955,592	723,774	4,666,278	121,160,903	22,623,922	8,346,238
Inventory	317,756	-	313,849	7,540,144	4,009,420	809,291
Inter-company receivables	-	-	-	606,636	1,469,846	-
Other current assets	350,366	-	1,002,126	10,684,153	786,622	432,494
Current assets	11,546,545	2,292,632	10,879,904	169,384,749	28,896,887	9,588,022
Property plant & equipment	27,894,713	3,170,848	22,148,676	887,619,619	300,417,625	27,045,705
Accumulated depreciation & amortization	(14,576,355)	(1,248,017)	(14,031,987)	(444,783,585)	(117,445,651)	(9,149,810)
	13,318,357	1,922,831	8,116,689	442,836,034	182,971,974	17,895,896
Regulatory assets (net)	-	73,468	4,170,992	-	2,181,619	3,057,708
Inter-company investments	-	-	100	-	-	-
Other non-current assets	64,208	144,526	46,856	21,115,971	19,420,123	-
Total Assets	$ 24,929,110	$ 4,433,457	$ 23,214,541	$ 633,336,754	$ 233,470,603	$ 30,541,626
Accounts payable & accrued charges	$ 7,798,003	$ 794,695	$ 4,858,519	$ 101,036,445	$ 9,978,464	$ 10,621,352
Future income tax liabilities - current	-	-	-	358,217	-	-
Other current liabilities	37,219	-	53,590	-	503,999	929,119
Inter-company payables	-	-	2,179,206	1,417,188	19,533,567	-
Loans and notes payable, and current portion of long term debt	228,728	-	-	2,922,591	9,403,100	547,485
Current liabilities	8,063,950	794,695	7,091,316	105,734,441	39,419,130	12,097,956
Long-term debt	2,700,000	-	7,200,000	290,000,000	50,000,000	485,915
Inter-company long-term debt & advances	1,710,170	-	-	-	-	8,038,524
Regulatory liabilities (net)	1,364,986	-	-	4,607,195	-	-
Other deferred amounts & customer deposits	-	30,052	850,614	20,739,178	25,322,719	780,947
Employee future benefits	308,029	-	686,906	3,783,173	33,936,884	514,103
Future income tax liabilities	-	-	-	-	-	-
Total Liabilities	14,147,136	824,748	15,828,836	424,863,987	148,678,733	21,917,445
Shareholders' Equity	10,781,975	3,608,709	7,385,705	208,472,767	84,791,870	8,624,181
LIABILITIES & SHAREHOLDERS' EQUITY	$ 24,929,110	$ 4,433,457	$ 23,214,541	$ 633,336,754	$ 233,470,603	$ 30,541,626

Balance Sheet As of December 31, 2010	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.	Grimsby Power Incorporated
Cash & cash equivalents	$ 885,255	$ 3,328,924	$ 1,089,077	$ 2,093,677	$ 2,700,894	$ 1,602,923
Receivables	1,510,428	12,417,731	9,358,030	3,369,484	25,728,431	2,603,820
Inventory	96,441	60,000	94,980	119,690	1,022,657	227,793
Inter-company receivables	-	-	270,311	-	-	12,333
Other current assets	41,561	147,176	209,158	268,567	-	121,924
Current assets	2,533,685	15,953,831	11,021,556	5,851,418	29,451,982	4,568,793
Property plant & equipment	6,900,381	53,338,003	77,484,151	10,617,986	169,076,501	24,007,789
Accumulated depreciation & amortization	(4,661,945)	(16,295,695)	(43,971,825)	(7,543,755)	(103,658,920)	(12,700,493)
	2,238,435	37,042,308	33,512,326	3,074,231	65,417,581	11,307,296
Regulatory assets (net)	841,479	1,709,395	-	140,875	1,797,473	-
Inter-company investments	-	-	-	-	400,000	94,500
Other non-current assets	115,798	-	2,671,384	-	7,975,566	1,053,766
Total Assets	$ 5,729,397	$ 54,705,533	$ 47,205,266	$ 9,066,524	$ 105,042,602	$ 17,024,355
Accounts payable & accrued charges	$ 2,275,586	$ 10,721,917	$ 6,781,528	$ 1,341,482	$ 14,363,358	$ 2,093,530
Future income tax liabilities - current	-	-	-	-	560,504	-
Other current liabilities	73,725	251,663	305,971	82,925	43,341	25,236
Inter-company payables	-	-	15,600,000	-	49,880,184	-
Loans and notes payable, and current portion of long term debt	-	3,724,979	126,908	-	705,102	525,916
Current liabilities	2,349,312	14,698,558	22,814,407	1,424,407	65,552,489	2,644,683
Long-term debt	-	18,202,843	2,331,833	-	-	1,493,333
Inter-company long-term debt & advances	1,524,511	-	-	-	-	5,782,746
Regulatory liabilities (net)	-	-	1,148,704	-	-	159,198
Other deferred amounts & customer deposits	65,287	607,327	670,645	2,028,717	1,443,524	781,783
Employee future benefits	-	4,280,137	1,342,826	-	16,207,556	-
Future income tax liabilities	128,876	-	-	-	7,975,566	-
Total Liabilities	4,067,986	37,788,865	28,308,416	3,453,124	91,179,135	10,861,742
Shareholders' Equity	1,661,412	16,916,668	18,896,850	5,613,400	13,863,467	6,162,613
LIABILITIES & SHAREHOLDERS' EQUITY	$ 5,729,397	$ 54,705,533	$ 47,205,266	$ 9,066,524	$ 105,042,602	$ 17,024,355

Balance Sheet As of December 31, 2010	Guelph Hydro Electric Systems Inc.	Haldimand County Hydro Inc.	Halton Hills Hydro Inc.	Hearst Power Distribution Company Limited	Horizon Utilities Corporation	Hydro 2000 Inc.
Cash & cash equivalents	$ 23,617,298	$ 2,494,213	$ 2,392,329	$ 4,441,762	$ 10,446,143	$ 375,082
Receivables	20,562,022	8,560,407	10,155,512	1,303,668	87,300,073	229,744
Inventory	1,554,850	1,113,623	493,907	108,393	6,041,590	-
Inter-company receivables	92,359	-	137,876	-	-	-
Other current assets	2,909,020	1,394,533	409,249	58,980	2,159,247	38,931
Current assets	48,735,549	13,562,777	13,588,873	5,912,803	105,947,053	643,757
Property plant & equipment	146,740,503	57,445,569	49,227,467	3,852,480	660,045,097	875,819
Accumulated depreciation & amortization	(57,132,454)	(22,697,860)	(19,122,862)	(3,066,689)	(327,086,844)	(429,406)
	89,608,048	34,747,709	30,104,605	785,791	332,958,253	446,413
Regulatory assets (net)	-	2,576,730	7,002,743	-	-	174,178
Inter-company investments	-	-	1	-	99,900	-
Other non-current assets	8,079,117	-	21,356	99,900	10,751,206	-
Total Assets	$ 146,422,714	$ 50,887,216	$ 50,717,578	$ 6,798,494	$ 449,756,412	$ 1,264,348
Accounts payable & accrued charges	$ 13,938,133	$ 7,108,544	$ 8,158,357	$ 1,531,853	$ 72,112,382	$ 362,016
Future income tax liabilities - current	-	-	-	-	-	-
Other current liabilities	432,256	265,934	161,190	-	1,216,830	15
Inter-company payables	1,617,499	582,405	-	-	22,305,839	-
Loans and notes payable, and current portion of long term debt	237,727	1,188,495	3,500,000	-	-	-
Current liabilities	16,225,615	9,145,378	11,819,547	1,531,853	95,635,051	362,031
Long-term debt	65,000,000	8,770,604	-	-	-	-
Inter-company long-term debt & advances	-	-	16,141,969	1,700,000	156,000,000	184,245
Regulatory liabilities (net)	6,435,895	-	-	623,779	3,095,244	-
Other deferred amounts & customer deposits	2,536,862	333,740	672,317	58,327	256,670	12,660
Employee future benefits	8,977,356	-	488,555	-	16,292,680	-
Future income tax liabilities	-	-	-	-	-	-
Total Liabilities	99,175,728	18,249,723	29,122,388	3,913,959	271,279,644	558,936
Shareholders' Equity	47,246,986	32,637,493	21,595,190	2,884,535	178,476,768	705,412
LIABILITIES & SHAREHOLDERS' EQUITY	$ 146,422,714	$ 50,887,216	$ 50,717,578	$ 6,798,494	$ 449,756,412	$ 1,264,348

Balance Sheet As of December 31, 2010	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.	Hydro Ottawa Limited	Innisfil Hydro Distribution Systems Limited	Kenora Hydro Electric Corporation Ltd.
Cash & cash equivalents	$ 1,106,176	$ -	$ 0	$ 2,924,135	$ -	$ 582,143
Receivables	3,097,488	53,895,946	764,679,081	151,831,477	7,975,725	2,432,832
Inventory	125,669	1,086,804	4,993,868	8,531,998	427,863	280,871
Inter-company receivables	-	-	30,941,274	-	-	-
Other current assets	222,722	2,728,089	13,723,560	6,908,731	303,127	50,677
Current assets	4,552,055	57,710,839	814,337,783	170,196,341	8,706,716	3,346,523
Property plant & equipment	3,570,854	503,721,667	7,978,574,009	975,061,707	50,156,164	14,171,454
Accumulated depreciation & amortization	(1,614,113)	(244,882,636)	(2,821,209,799)	(442,289,438)	(27,555,405)	(6,833,326)
	1,956,741	258,839,031	5,157,364,209	532,772,269	22,600,758	7,338,128
Regulatory assets (net)	-	15,311,139	138,802,607	-	2,176,013	78,835
Inter-company investments	-	-	0	-	-	-
Other non-current assets	183,560	13,227,522	164,626,835	-	1,656,721	964,644
Total Assets	$ 6,692,355	$ 345,088,531	$ 6,275,131,435	$ 702,968,610	$ 35,140,207	$ 11,728,129
Accounts payable & accrued charges	$ 2,460,588	$ 59,098,526	$ 467,412,288	$ 112,115,744	$ 5,774,451	$ 1,429,921
Future income tax liabilities - current	-	68,900	17,364,376	-	17,000	-
Other current liabilities	-	2,175,025	83,822,799	2,646,904	716,949	7,049
Inter-company payables	231,425	-	-	2,355,466	138	422,263
Loans and notes payable, and current portion of long term debt	-	16,034,798	207,352,904	-	6,916,929	-
Current liabilities	2,692,013	77,377,249	775,952,367	117,118,114	13,425,466	1,859,233
Long-term debt	-	-	-	-	2,027,644	1,300,000
Inter-company long-term debt & advances	500,290	143,000,000	2,669,482,635	312,185,000	3,666,000	3,069,279
Regulatory liabilities (net)	333,709	-	-	1,165,837	-	-
Other deferred amounts & customer deposits	461,568	167,539	156,518,045	12,081,639	351,008	67,876
Employee future benefits	-	6,120,000	543,073,242	5,159,305	-	207,673
Future income tax liabilities	-	7,831,310	153,766,533	-	-	-
Total Liabilities	3,987,581	234,496,099	4,298,792,821	447,709,895	19,470,118	6,504,061
Shareholders' Equity	2,704,775	110,592,432	1,976,338,614	255,258,715	15,670,090	5,224,069
LIABILITIES & SHAREHOLDERS' EQUITY	$ 6,692,355	$ 345,088,531	$ 6,275,131,435	$ 702,968,610	$ 35,140,207	$ 11,728,129

Balance Sheet As of December 31, 2010	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	London Hydro Inc.	Middlesex Power Distribution Corporation
Cash & cash equivalents	$ 2,303,849	$ 28,003,063	$ 3,651,326	$ -	$ 7,667,205	$ 1,323,971
Receivables	13,701,276	34,917,728	5,287,085	4,404,238	53,718,848	3,205,641
Inventory	1,042,344	3,668,935	239,490	238,322	4,649,721	220,709
Inter-company receivables	-	89,840	-	-	-	-
Other current assets	2,309,582	1,159,155	565,547	348,818	1,921,526	85,994
Current assets	19,357,051	67,838,721	9,743,448	4,991,379	67,957,300	4,836,315
Property plant & equipment	47,761,760	277,562,809	18,318,393	23,316,903	369,927,352	19,663,372
Accumulated depreciation & amortization	(19,035,171)	(130,416,305)	(7,412,315)	(9,390,834)	(174,378,674)	(10,984,777)
	28,726,589	147,146,504	10,906,078	13,926,069	195,548,679	8,678,594
Regulatory assets (net)	2,077,621	8,382,364	1,403,440	1,590,212	14,617,745	1,726,726
Inter-company investments	-	-	-	-	-	-
Other non-current assets	-	1,310,028	-	917,600	92,300	-
Total Assets	$ 50,161,261	$ 224,677,617	$ 22,052,967	$ 21,425,260	$ 278,216,024	$ 15,241,636
Accounts payable & accrued charges	$ 9,655,779	$ 27,211,937	$ 3,019,317	$ 4,695,288	$ 34,504,905	$ 2,711,891
Future income tax liabilities - current	-	-	-	-	-	-
Other current liabilities	-	264,371	97,268	31,542	2,554,373	8,767
Inter-company payables	-	-	-	312,517	6,987,124	686,737
Loans and notes payable, and current portion of long term debt	5,995,989	893,011	-	767,370	2,304,000	-
Current liabilities	15,651,768	28,369,319	3,116,585	5,806,717	46,350,402	3,407,395
Long-term debt	2,316,421	-	3,547,658	3,487,500	20,650,000	-
Inter-company long-term debt & advances	10,880,619	85,713,896	7,000,000	-	70,000,000	5,800,000
Regulatory liabilities (net)	-	-	-	-	-	-
Other deferred amounts & customer deposits	676,267	3,887,326	77,994	263,324	12,138,800	1,288,984
Employee future benefits	1,049,074	5,381,064	268,943	-	9,864,100	53,515
Future income tax liabilities	-	-	-	-	-	-
Total Liabilities	30,574,149	123,351,605	14,011,180	9,557,542	159,003,301	10,549,894
Shareholders' Equity	19,587,112	101,326,013	8,041,787	11,867,718	119,212,722	4,691,742
LIABILITIES & SHAREHOLDERS' EQUITY	$ 50,161,261	$ 224,677,617	$ 22,052,967	$ 21,425,260	$ 278,216,024	$ 15,241,636

Balance Sheet As of December 31, 2010	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket - Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.	Norfolk Power Distribution Inc.
Cash & cash equivalents	$ 177,301	$ 3,856,689	$ 6,647,887	$ 8,025,373	$ 239,382	$ 836,521
Receivables	3,844,978	15,050,736	9,171,322	22,272,107	4,471,666	9,092,498
Inventory	46,043	915,667	661,486	1,616,141	218,510	549,678
Inter-company receivables	-	17,468	-	21,514	-	259,756
Other current assets	356,573	298,169	163,309	4,786,072	92,379	319,822
Current assets	4,424,895	20,138,729	16,644,003	36,721,207	5,021,936	11,058,275
Property plant & equipment	22,256,054	97,676,195	98,387,508	244,134,299	39,717,803	75,225,238
Accumulated depreciation & amortization	(11,383,077)	(47,689,186)	(47,359,017)	(125,943,370)	(19,895,705)	(25,835,328)
	10,872,977	49,987,009	51,028,490	118,190,929	19,822,098	49,389,910
Regulatory assets (net)	630,849	-	2,202,000	-	1,219,676	1,121,265
Inter-company investments	-	-	-	-	-	-
Other non-current assets	1,260,100	997,389	4,220,000	-	1,228,448	1,215,250
Total Assets	$ 17,188,821	$ 71,123,128	$ 74,094,493	$ 154,912,136	$ 27,292,158	$ 62,784,699
Accounts payable & accrued charges	$ 3,400,503	$ 11,841,852	$ 4,732,434	$ 14,206,267	$ 3,097,275	$ 6,301,538
Future income tax liabilities - current	-	-	-	-	-	-
Other current liabilities	65,525	1,618	228,683	1,222	84,216	106,209
Inter-company payables	-	-	-	7,074,946	-	177,275
Loans and notes payable, and current portion of long term debt	1,955,752	402,934	25,930	2,116,973	3,849,383	918,149
Current liabilities	5,421,779	12,246,403	4,987,047	23,399,408	7,030,874	7,503,172
Long-term debt	2,213,891	6,789,443	-	13,634,272	1,350,462	26,636,971
Inter-company long-term debt & advances	-	14,934,210	25,609,337	25,605,090	5,746,838	-
Regulatory liabilities (net)	-	2,460,721	-	7,736,478	-	-
Other deferred amounts & customer deposits	202,741	3,869,398	3,553,519	1,207,795	371,992	121,909
Employee future benefits	74,625	183,993	819,042	3,657,023	460,985	867,800
Future income tax liabilities	-	-	-	-	-	-
Total Liabilities	7,913,036	40,484,169	34,968,945	75,240,066	14,961,150	35,129,852
Shareholders' Equity	9,275,785	30,638,959	39,125,548	79,672,071	12,331,008	27,654,847
LIABILITIES & SHAREHOLDERS' EQUITY	$ 17,188,821	$ 71,123,128	$ 74,094,493	$ 154,912,136	$ 27,292,158	$ 62,784,699

Balance Sheet As of December 31, 2010	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation	Oshawa PUC Networks Inc.
Cash & cash equivalents	$ 5,900,680	$ 470,421	$ 1,617,735	$ 1,271,038	$ 1,602,156	$ 15,508,847
Receivables	12,716,419	2,833,986	29,539,998	5,704,155	6,579,300	19,291,713
Inventory	786,111	355,124	3,631,581	273,873	597,245	333,084
Inter-company receivables	453,310	18,013	-	-	1,276,448	-
Other current assets	748,915	103,558	676,737	228,621	377,271	783,266
Current assets	20,605,436	3,781,102	35,466,051	7,477,687	10,432,420	35,916,910
Property plant & equipment	86,611,880	6,603,401	210,581,961	30,611,560	32,962,623	134,986,328
Accumulated depreciation & amortization	(48,981,464)	(3,119,295)	(85,365,493)	(16,588,792)	(17,572,232)	(82,890,064)
	37,630,416	3,484,106	125,216,468	14,022,768	15,390,391	52,096,264
Regulatory assets (net)	2,470,136	528,673	2,067,770	-	1,049,083	2,653,350
Inter-company investments	-	-	-	65,000	-	-
Other non-current assets	-	-	22,445,475	530,000	1,562,251	2,630
Total Assets	$ 60,705,988	$ 7,793,881	$ 185,195,765	$ 22,095,455	$ 28,434,145	$ 90,669,154
Accounts payable & accrued charges	$ 7,684,236	$ 1,763,466	$ 31,387,837	$ 3,552,764	$ 5,648,332	$ 13,103,002
Future income tax liabilities - current	0	-	-	-	-	-
Other current liabilities	559,037	8,337	292,531	21,400	169,621	210,960
Inter-company payables	214,884	-	-	-	34,616	-
Loans and notes payable, and current portion of long term debt	-	181,333	-	515,662	-	-
Current liabilities	8,458,157	1,953,136	31,680,368	4,089,826	5,852,569	13,313,962
Long-term debt	2,785,974	2,236,572	-	7,446,118	1,995,000	7,000,000
Inter-company long-term debt & advances	19,511,601	-	74,577,504	-	9,762,000	23,064,000
Regulatory liabilities (net)	-	-	-	545,041	-	-
Other deferred amounts & customer deposits	950,211	127,482	31,744,530	507,868	599,566	4,285,818
Employee future benefits	4,208,039	47,786	7,472,700	226,107	547,238	10,196,920
Future income tax liabilities	-	1,454	-	-	-	-
Total Liabilities	35,913,982	4,366,431	145,475,102	12,814,959	18,756,373	57,860,700
Shareholders' Equity	24,792,006	3,427,450	39,720,662	9,280,496	9,677,772	32,808,454
LIABILITIES & SHAREHOLDERS' EQUITY	$ 60,705,988	$ 7,793,881	$ 185,195,765	$ 22,095,455	$ 28,434,145	$ 90,669,154

Balance Sheet As of December 31, 2010	Ottawa River Power Corporation	Parry Sound Power Corporation	Peterborough Distribution Incorporated	Port Colborne Hydro Inc.	PowerStream Inc.	PUC Distribution Inc.
Cash & cash equivalents	$ 7,852,408	$ 469,102	$ 7,338,786	$ 275	$ 8,567,849	$ 6,020,883
Receivables	3,891,710	1,964,511	13,673,952	3,650,461	160,030,375	13,665,987
Inventory	787,727	113,629	1,209,115	-	3,049,556	1,306,185
Inter-company receivables	235,306	-	22,795,000	-	2,435,016	-
Other current assets	293,697	295,830	162,961	83,782	2,719,396	257,277
Current assets	13,060,848	2,843,072	45,179,814	3,734,518	176,802,193	21,250,332
Property plant & equipment	24,388,799	10,814,456	77,625,384	14,268,371	1,308,232,552	89,978,517
Accumulated depreciation & amortization	(16,217,706)	(6,965,574)	(29,619,450)	(2,174,231)	(619,451,273)	(47,689,616)
	8,171,093	3,848,883	48,005,934	12,094,140	688,781,279	42,288,901
Regulatory assets (net)	-	703,276	6,960,457	2,720,494	-	1,958,094
Inter-company investments	-	100	-	-	-	-
Other non-current assets	812,550	290,108	1,930,000	347,333	53,924,935	-
Total Assets	$ 22,044,491	$ 7,685,439	$ 102,076,205	$ 18,896,486	$ 919,508,407	$ 65,497,327
Accounts payable & accrued charges	$ 3,873,525	$ 1,937,279	$ 11,407,782	$ 394,165	$ 108,868,988	$ 4,323,866
Future income tax liabilities - current	-	-	-	-	-	-
Other current liabilities	924	24,708	174,133	20	6,705,145	-
Inter-company payables	-	744,495	-	18,517,256	12,160,585	938,444
Loans and notes payable, and current portion of long term debt	101,243	-	814,959	-	45,577,023	4,999,600
Current liabilities	3,975,693	2,706,482	12,396,874	18,911,441	173,311,741	10,261,910
Long-term debt	-	-	37,490,888	-	173,765,022	5,000,000
Inter-company long-term debt & advances	5,585,838	2,433,728	23,157,680	-	182,429,859	26,534,040
Regulatory liabilities (net)	4,398,585	-	-	-	34,811,288	-
Other deferred amounts & customer deposits	537,616	128,229	741,622	-	54,505,799	3,112,732
Employee future benefits	-	-	6,077	-	14,007,126	-
Future income tax liabilities	-	-	-	241,554	61,264	-
Total Liabilities	14,497,732	5,268,439	73,793,141	19,152,996	632,892,100	44,908,682
Shareholders' Equity	7,546,759	2,417,000	28,283,064	(256,510)	286,616,306	20,588,645
LIABILITIES & SHAREHOLDERS' EQUITY	$ 22,044,491	$ 7,685,439	$ 102,076,205	$ 18,896,486	$ 919,508,407	$ 65,497,327

Balance Sheet As of December 31, 2010	Renfrew Hydro Inc.	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.	Tillsonburg Hydro Inc.
Cash & cash equivalents	$ 1,386,524	$ 669,482	$ 793,425	$ 745,185	$ 8,308,224	$ 2,957,459
Receivables	1,939,628	2,318,619	2,038,379	5,706,251	9,041,413	2,379,169
Inventory	265,958	251,106	44,830	-	1,270,878	343,563
Inter-company receivables	23,802	-	-	-	500,259	-
Other current assets	126,214	24,000	365,803	1,346,970	976,159	56,900
Current assets	3,742,126	3,263,207	3,242,436	7,798,406	20,096,933	5,737,092
Property plant & equipment	12,711,556	6,028,198	7,460,625	39,362,298	148,884,341	14,719,786
Accumulated depreciation & amortization	(8,199,560)	(1,904,543)	(2,932,349)	(20,614,926)	(85,340,675)	(8,789,031)
	4,511,996	4,123,655	4,528,276	18,747,372	63,543,666	5,930,755
Regulatory assets (net)	-	448,190	184,735	1,172,463	4,935,307	862,270
Inter-company investments	-	-	-	-	-	-
Other non-current assets	97,522	-	133,236	691,006	5,800,581	125,906
Total Assets	$ 8,351,644	$ 7,835,052	$ 8,088,683	$ 28,409,247	$ 94,376,486	$ 12,656,022
Accounts payable & accrued charges	$ 785,766	$ 1,328,169	$ 4,451,836	$ 3,109,437	$ 4,805,803	$ 2,334,903
Future income tax liabilities - current	-	-	-	-	-	-
Other current liabilities	-	65,086	23,235	187,788	207,955	-
Inter-company payables	234,045	333,025	212,956	1,121,525	66,540	117,637
Loans and notes payable, and current portion of long term debt	-	113,965	229,278	750,000	387,529	103,141
Current liabilities	1,019,811	1,840,245	4,917,305	5,168,751	5,467,827	2,555,681
Long-term debt	194,219	892,143	-	2,500,000	7,097,218	1,158,408
Inter-company long-term debt & advances	2,705,168	1,506,383	-	7,714,426	33,490,500	-
Regulatory liabilities (net)	1,000,220	-	-	-	-	-
Other deferred amounts & customer deposits	171,891	44,833	163,568	684,860	684,884	153,073
Employee future benefits	-	-	45,989	-	2,291,374	-
Future income tax liabilities	-	-	-	-	-	-
Total Liabilities	5,091,309	4,283,605	5,126,862	16,068,036	49,031,803	3,867,163
Shareholders' Equity	3,260,335	3,551,447	2,961,821	12,341,211	45,344,683	8,788,860
LIABILITIES & SHAREHOLDERS' EQUITY	$ 8,351,644	$ 7,835,052	$ 8,088,683	$ 28,409,247	$ 94,376,486	$ 12,656,022

Balance Sheet As of December 31, 2010	Toronto Hydro-Electric System Limited	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.	Wellington North Power Inc.
Cash & cash equivalents	$ 180,228,697	$ -	$ 2,161,767	$ 130,887	$ 7,331,443	$ 584,146
Receivables	460,293,153	54,746,878	2,931,772	27,909,927	8,321,609	1,887,072
Inventory	7,501,047	1,445,419	-	2,496,403	571,394	-
Inter-company receivables	1,131,748	-	3,340,382	-	125,829	-
Other current assets	3,774,701	724,934	188,277	485,686	92,231	5,356
Current assets	652,929,346	56,917,231	8,622,198	31,022,902	16,442,506	2,476,574
Property plant & equipment	4,431,116,520	352,694,214	19,735,503	233,036,893	48,097,503	10,631,501
Accumulated depreciation & amortization	(2,283,939,226)	(185,648,588)	(10,915,212)	(105,250,602)	(26,293,738)	(5,841,908)
	2,147,177,293	167,045,626	8,820,291	127,786,291	21,803,765	4,789,593
Regulatory assets (net)	36,712,712	-	-	-	217,350	-
Inter-company investments	-	-	-	-	-	-
Other non-current assets	7,517,642	12,072,755	154,053	50,779	3,012,019	383,745
Total Assets	$ 2,844,336,993	$ 236,035,612	$ 17,596,542	$ 158,859,972	$ 41,475,640	$ 7,649,912
Accounts payable & accrued charges	$ 357,535,002	$ 35,671,046	$ 2,494,355	$ 28,124,136	$ 6,092,133	$ 2,103,940
Future income tax liabilities - current	-	-	-	-	-	-
Other current liabilities	14,886,631	141,025	-	1,960,423	66,270	-
Inter-company payables	251,351,346	4,907,612	-	918	-	-
Loans and notes payable, and current portion of long term debt	-	12,451,228	-	2,781,517	21,780	-
Current liabilities	623,772,979	53,170,911	2,494,355	32,866,993	6,180,183	2,103,940
Long-term debt	-	-	-	11,579,167	3,700,000	876,122
Inter-company long-term debt & advances	1,110,596,785	82,406,435	3,593,269	33,513,211	13,499,953	1,085,016
Regulatory liabilities (net)	-	6,582,453	2,122,564	7,048,928	-	118,790
Other deferred amounts & customer deposits	50,400,345	8,972,888	-	2,218,135	2,905,498	335,587
Employee future benefits	166,070,000	-	-	4,034,195	1,535,617	103,322
Future income tax liabilities	-	11,868,013	-	-	-	381,600
Total Liabilities	1,950,840,109	163,000,700	8,210,188	91,260,629	27,821,251	5,004,377
Shareholders' Equity	893,496,884	73,034,912	9,386,354	67,599,343	13,654,389	2,645,534
LIABILITIES & SHAREHOLDERS' EQUITY	$ 2,844,336,993	$ 236,035,612	$ 17,596,542	$ 158,859,972	$ 41,475,640	$ 7,649,912

Balance Sheet As of December 31, 2010	West Coast Huron Energy Inc.	West Perth Power Inc.	Westario Power Inc.	Whitby Hydro Electric Corporation	Woodstock Hydro Services Inc.	Total Industry
Cash & cash equivalents	$ 157,373	$ 485,963	$ 4,531,244	$ 1,555,037	$ 3,188,152	$ 505,266,250
Receivables	1,369,126	1,226,714	8,646,125	16,944,952	8,156,584	2,534,705,499
Inventory	432,765	54,403	757,793	924,184	610,043	89,084,349
Inter-company receivables	-	417,066	-	-	2,782	68,479,172
Other current assets	9,291	962,940	566,094	221,951	277,401	77,940,468
Current assets	1,968,555	3,147,086	14,501,255	19,646,124	12,234,961	3,275,475,738
Property plant & equipment	6,375,533	5,211,314	46,215,928	128,917,771	38,216,262	21,870,246,751
Accumulated depreciation & amortization	(2,240,016)	(3,229,758)	(16,008,409)	(66,049,072)	(17,164,840)	(9,652,762,713)
	4,135,517	1,981,557	30,207,519	62,868,699	21,051,423	12,217,484,039
Regulatory assets (net)	526,790	-	3,395,437	-	-	318,429,185
Inter-company investments	-	-	-	-	-	1,204,613
Other non-current assets	32,219	-	227,288	4,858,765	2,446,790	404,935,718
Total Assets	$ 6,663,081	$ 5,128,642	$ 48,331,498	$ 87,373,588	$ 35,733,174	$ 16,217,529,293
Accounts payable & accrued charges	$ 686,798	$ 767,506	$ 6,738,617	$ 12,049,391	$ 5,711,469	$ 1,820,695,420
Future income tax liabilities - current	-	-	-	-	-	18,704,068
Other current liabilities	-	-	-	147,663	175,100	125,790,383
Inter-company payables	-	470,130	-	434,995	-	438,441,369
Loans and notes payable, and current portion of long term debt	-	6,125	451,814	-	113,468	352,716,960
Current liabilities	686,798	1,243,761	7,190,431	12,632,049	6,000,037	2,756,348,200
Long-term debt	-	1,183,391	10,330,382	-	12,653,654	907,204,048
Inter-company long-term debt & advances	974,454	-	5,260,461	28,337,942	-	5,465,819,020
Regulatory liabilities (net)	-	1,162,603	-	1,848,722	54,527	94,429,066
Other deferred amounts & customer deposits	266,126	67,794	-	978,578	1,495,806	445,063,290
Employee future benefits	203,760	-	346,753	-	1,142,616	897,019,708
Future income tax liabilities	-	-	212,000	-	-	184,337,432
Total Liabilities	2,131,138	3,657,549	23,340,026	43,797,290	21,346,640	10,750,220,765
Shareholders' Equity	4,531,943	1,471,093	24,991,472	43,576,298	14,386,534	5,467,308,527
LIABILITIES & SHAREHOLDERS' EQUITY	$ 6,663,081	$ 5,128,642	$ 48,331,498	$ 87,373,588	$ 35,733,174	$ 16,217,529,293

Income Statement For the year ended December 31, 2010	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brant County Power Inc.	Brantford Power Inc.	Burlington Hydro Inc.
Power and Distribution Revenue	$ 35,030,935	$ 3,110,255	$ 82,791,478	$ 24,560,547	$ 93,359,841	$ 145,389,828
Cost of Power and Related Costs	17,137,702	1,913,140	63,323,311	18,498,271	77,201,485	115,256,976
	17,893,233	1,197,115	19,468,167	6,062,276	16,158,356	30,132,852
Other Income	89,312	108,367	937,058	191,675	766,689	687,808
Expenses						
Operating	1,097,534	332,111	3,135,697	517,339	1,008,391	4,047,491
Maintenance	3,426,509	51,665	175,850	645,508	1,681,173	2,275,552
Administrative	4,123,260	615,874	6,943,273	2,329,572	4,895,375	7,678,010
Other	56,576	-	235,388	-	42,583	533,855
Depreciation and Amortization	3,926,973	221,088	3,939,847	1,037,085	3,748,622	6,581,092
Financing	3,337,785	93,733	1,571,418	387,129	2,068,517	3,425,562
	15,968,638	1,314,471	16,001,473	4,916,633	13,444,661	24,541,563
Net Income Before Taxes	2,013,907	(8,989)	4,403,752	1,337,318	3,480,385	6,279,097
PILs and Income Taxes						
Current	308,702	-	906,000	4,475	1,120,928	2,263,771
Future	288,684	(75,522)	-	392,870	486,000	(696,269)
	597,386	(75,522)	906,000	397,345	1,606,928	1,567,502
Net Income	$ 1,416,521	$ 66,533	$ 3,497,752	$ 939,973	$ 1,873,457	$ 4,711,595

Income Statement For the year ended December 31, 2010	Cambridge and North Dumfries Hydro Inc.	Canadian Niagara Power Inc.	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	Chatham-Kent Hydro Inc.	Clinton Power Corporation
Power and Distribution Revenue	$ 145,299,927	$ 40,878,003	$ 14,050,534	$ 2,797,323	$ 77,175,701	$ 2,728,161
Cost of Power and Related Costs	121,573,775	29,380,266	11,143,850	2,164,638	62,099,564	2,173,003
	23,726,152	11,497,737	2,906,685	632,685	15,076,136	555,158
Other Income	472,783	975,311	121,504	21,795	329,181	68,288
Expenses						
Operating	2,516,620	930,665	356,562	203,961	960,958	6,827
Maintenance	931,863	1,119,821	275,059	-	1,036,846	47,326
Administrative	6,132,074	3,353,485	1,098,759	335,034	4,471,544	505,034
Other	6,800	106,357	112,510	9,588	200,000	-
Depreciation and Amortization	6,145,892	3,048,005	605,257	40,368	3,666,128	79,194
Financing	1,910,786	2,172,046	381,772	2,894	1,692,009	85,711
	17,644,035	10,730,378	2,829,919	591,845	12,027,485	724,092
Net Income Before Taxes	6,554,900	1,742,670	198,269	62,635	3,377,833	(100,646)
PILs and Income Taxes						
Current	1,429,942	271,557	(220,447)	-	1,087,446	-
Future	-	-	100,262	-	-	-
	1,429,942	271,557	(120,185)	-	1,087,446	-
Net Income	$ 5,124,958	$ 1,471,112	$ 318,454	$ 62,635	$ 2,290,387	$ (100,646)

Income Statement For the year ended December 31, 2010	COLLUS Power Corporation	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Enersource Hydro Mississauga Inc.	EnWin Utilities Ltd.	Erie Thames Powerlines Corporation
Power and Distribution Revenue	$ 31,815,700	$ 3,144,729	$ 20,294,349	$ 720,364,646	$ 241,275,372	$ 39,462,213
Cost of Power and Related Costs	25,971,849	2,428,424	15,739,947	601,566,082	190,839,506	32,879,516
	5,843,852	716,305	4,554,402	118,798,564	50,435,866	6,582,697
Other Income	150,403	28,348	433,232	4,571,251	1,297,896	374,386
Expenses						
Operating	303,575	20,827	236,550	13,852,702	1,683,511	209,691
Maintenance	1,580,092	36,633	310,300	3,264,482	2,582,606	675,782
Administrative	2,110,582	415,399	1,536,447	29,699,967	17,196,932	3,551,535
Other	288,051	2,350	31,759	1,256,848	569,316	32,041
Depreciation and Amortization	967,205	140,803	824,357	36,253,284	12,249,956	1,177,338
Financing	249,634	519	289,953	19,047,065	3,981,428	596,577
	5,499,139	616,530	3,229,366	103,374,348	38,263,749	6,242,963
Net Income Before Taxes	495,116	128,124	1,758,268	19,995,467	13,470,013	714,120
PILs and Income Taxes						
Current	74,564	20,868	580,220	6,586,177	2,187,812	176,000
Future	21,814	(5,012)	-	620,078	-	-
	96,378	15,856	580,220	7,206,255	2,187,812	176,000
Net Income	$ 398,738	$ 112,268	$ 1,178,048	$ 12,789,212	$ 11,282,201	$ 538,120

Income Statement For the year ended December 31, 2010	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.	Grimsby Power Incorporated
Power and Distribution Revenue	$ 5,996,573	$ 60,320,805	$ 57,325,266	$ 7,298,677	$ 102,368,581	$ 18,922,453
Cost of Power and Related Costs	4,629,314	49,232,444	47,510,527	5,722,105	79,191,698	15,351,169
	1,367,258	11,088,360	9,814,739	1,576,573	23,176,883	3,571,284
Other Income	29,415	517,193	378,463	134,329	614,057	121,081
Expenses						
Operating	195,034	740,910	574,450	192,399	3,432,872	179,324
Maintenance	282,982	1,444,596	872,068	183,394	1,681,643	397,852
Administrative	550,700	3,294,849	2,543,298	949,892	3,025,366	1,203,411
Other	18,327	68,136	50,045	12,850	23,784	25,130
Depreciation and Amortization	214,565	2,453,626	2,605,175	357,117	4,959,843	975,166
Financing	97,811	1,217,525	1,218,158	6,978	4,445,828	459,637
	1,359,420	9,219,641	7,863,194	1,702,629	17,569,336	3,240,520
Net Income Before Taxes	37,254	2,385,912	2,330,009	8,273	6,221,604	451,845
PILs and Income Taxes						
Current	-	422,027	723,000	(8,780)	1,491,956	82,162
Future	13,078	-	-	-	-	98,229
	13,078	422,027	723,000	(8,780)	1,491,956	180,391
Net Income	$ 24,176	$ 1,963,885	$ 1,607,009	$ 17,053	$ 4,729,648	$ 271,454

Income Statement For the year ended December 31, 2010	Guelph Hydro Electric Systems Inc.	Haldimand County Hydro Inc.	Halton Hills Hydro Inc.	Hearst Power Distribution Company Limited	Horizon Utilities Corporation	Hydro 2000 Inc.
Power and Distribution Revenue	$ 142,623,588	$ 51,063,332	$ 51,202,201	$ 7,023,802	$ 503,133,102	$ 1,953,315
Cost of Power and Related Costs	117,703,271	37,439,461	41,442,197	6,207,910	413,458,388	1,628,541
	24,920,317	13,623,872	9,760,004	815,892	89,674,713	324,773
Other Income	1,519,926	684,308	120,931	118,680	1,384,945	15,324
Expenses						
Operating	928,997	1,450,067	892,153	91,992	14,209,111	-
Maintenance	1,654,809	2,192,433	275,320	292,585	4,210,648	4,446
Administrative	7,205,802	3,180,883	3,212,405	434,979	20,322,640	291,902
Other	269,223	71,140	136,758	-	744,408	2,000
Depreciation and Amortization	7,371,338	2,828,466	2,392,473	101,176	24,596,684	55,342
Financing	2,813,214	563,732	1,078,805	17,274	9,423,229	18,509
	20,243,382	10,286,722	7,987,914	938,007	73,506,720	372,199
Net Income Before Taxes	6,196,862	4,021,458	1,893,021	(3,434)	17,552,938	(32,102)
PILs and Income Taxes						
Current	3,482,474	1,574,922	558,014	(5,650)	5,717,506	14,424
Future	(1,403,110)	(341,873)	-	(4,000)	-	(19,358)
	2,079,364	1,233,049	558,014	(9,650)	5,717,506	(4,934)
Net Income	$ 4,117,497	$ 2,788,409	$ 1,335,007	$ 6,216	$ 11,835,432	$ (27,168)

Income Statement For the year ended December 31, 2010	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.	Hydro Ottawa Limited	Innisfil Hydro Distribution Systems Limited	Kenora Hydro Electric Corporation Ltd.
Power and Distribution Revenue	$ 11,549,216	$ 381,617,091	$ 3,297,105,965	$ 768,283,031	$ 28,346,312	$ 10,664,884
Cost of Power and Related Costs	10,221,319	318,203,294	2,155,665,224	619,900,047	20,393,170	8,470,634
	1,327,897	63,413,797	1,141,440,741	148,382,984	7,953,141	2,194,249
Other Income	52,414	1,905,276	32,221,592	8,145,458	38,129	133,953
Expenses						
Operating	75,104	3,572,499	75,489,061	11,971,416	870,153	115,598
Maintenance	131,509	3,014,674	230,172,072	5,663,033	436,210	339,740
Administrative	661,075	13,596,029	241,438,552	37,587,967	2,602,029	1,262,149
Other	15,678	-	8,066,769	2,636,988	23,661	11,748
Depreciation and Amortization	158,511	17,638,874	277,709,262	43,196,700	1,965,295	460,290
Financing	64,737	9,671,060	138,842,111	15,785,223	546,512	100,607
	1,106,615	47,493,136	971,717,827	116,841,326	6,443,859	2,290,133
Net Income Before Taxes	273,696	17,825,938	201,944,506	39,687,116	1,547,412	38,070
PILs and Income Taxes						
Current	(161,142)	4,057,139	7,983,019	13,316,081	825,000	(10,043)
Future	288,402	620,957	-	-	(198,000)	-
	127,260	4,678,096	7,983,019	13,316,081	627,000	(10,043)
Net Income	$ 146,436	$ 13,147,843	$ 193,961,487	$ 26,371,035	$ 920,412	$ 48,113

Income Statement For the year ended December 31, 2010	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	London Hydro Inc.	Middlesex Power Distribution Corporation
Power and Distribution Revenue	$ 68,426,296	$ 193,619,549	$ 25,123,258	$ 21,951,593	$ 340,504,315	$ 21,635,535
Cost of Power and Related Costs	58,581,045	156,940,481	20,764,427	17,170,452	278,618,382	18,336,673
	9,845,251	36,679,069	4,358,831	4,781,141	61,885,933	3,298,862
Other Income	333,109	932,927	167,084	184,998	630,828	198,441
Expenses						
Operating	2,404,496	2,824,720	415,821	164,974	7,101,230	105,854
Maintenance	940,362	4,069,611	225,312	764,547	6,304,713	295,100
Administrative	2,657,828	5,376,627	1,458,558	2,010,386	16,572,387	1,300,104
Other	155,272	488,057	46,698	10,549	107,252	7,982
Depreciation and Amortization	2,250,071	9,798,634	894,073	965,503	15,950,097	682,353
Financing	982,984	5,092,946	581,259	209,252	4,895,965	400,110
	9,391,013	27,650,594	3,621,720	4,125,212	50,931,644	2,791,504
Net Income Before Taxes	787,347	9,961,402	904,195	840,927	11,585,117	705,799
PILs and Income Taxes						
Current	266,201	2,193,378	254,247	212,816	2,535,544	227,105
Future	(9,645)	-	40,000	(159,969)	-	-
	256,556	2,193,378	294,247	52,847	2,535,544	227,105
Net Income	$ 530,791	$ 7,768,024	$ 609,948	$ 788,080	$ 9,049,573	$ 478,694

Income Statement For the year ended December 31, 2010	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket - Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.	Norfolk Power Distribution Inc.
Power and Distribution Revenue	$ 21,741,486	$ 75,263,003	$ 75,326,635	$ 133,418,331	$ 19,187,280	$ 42,120,027
Cost of Power and Related Costs	18,173,779	62,730,719	59,548,941	105,981,287	14,509,994	31,033,780
	3,567,707	12,532,285	15,777,694	27,437,044	4,677,285	11,086,247
Other Income	100,517	1,945,693	704,584	1,110,114	251,160	170,597
Expenses						
Operating	191,621	721,854	864,406	3,305,582	350,388	1,106,741
Maintenance	436,383	976,540	1,295,024	2,385,167	394,912	1,115,511
Administrative	1,219,852	3,894,123	4,516,217	7,684,626	1,024,249	2,696,758
Other	30,467	23,784	615,157	87,092	31,673	74,556
Depreciation and Amortization	773,443	3,321,144	4,477,575	8,248,084	1,386,007	2,351,567
Financing	126,056	1,313,194	1,599,833	2,705,114	685,629	1,380,824
	2,777,822	10,250,639	13,368,212	24,415,666	3,872,856	8,725,956
Net Income Before Taxes	890,402	4,227,339	3,114,066	4,131,491	1,055,589	2,530,888
PILs and Income Taxes						
Current	85,807	1,077,884	1,040,514	2,050,722	99,209	531,000
Future	-	(574,309)	-	(453,030)	221,254	-
	85,807	503,575	1,040,514	1,597,692	320,463	531,000
Net Income	$ 804,595	$ 3,723,764	$ 2,073,553	$ 2,533,799	$ 735,126	$ 1,999,888

Income Statement For the year ended December 31, 2010	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation	Oshawa PUC Networks Inc.
Power and Distribution Revenue	$ 55,790,495	$ 12,994,954	$ 161,492,792	$ 25,639,341	$ 32,409,199	$ 99,613,549
Cost of Power and Related Costs	44,267,559	10,308,323	130,384,214	20,665,785	24,996,496	79,731,110
	11,522,936	2,686,631	31,108,578	4,973,555	7,412,703	19,882,439
Other Income	119,101	29,595	1,884,269	194,529	98,099	575,750
Expenses						
Operating	660,621	401,967	4,510,206	392,746	1,075,707	548,160
Maintenance	1,146,781	343,735	1,922,776	425,049	681,933	1,028,033
Administrative	3,068,682	1,307,987	4,584,761	1,821,925	2,425,611	7,258,314
Other	95,460	2,913	232,848	6,286	51,960	200,584
Depreciation and Amortization	2,789,534	295,966	9,996,871	1,051,344	1,399,577	4,389,959
Financing	1,028,552	123,656	5,426,179	411,625	688,232	2,043,621
	8,789,630	2,476,224	26,673,641	4,108,974	6,323,020	15,468,671
Net Income Before Taxes	2,852,407	240,002	6,319,207	1,059,110	1,187,782	4,989,518
PILs and Income Taxes						
Current	734,285	27,613	699,709	285,235	454,000	1,885,201
Future	-	4,870	973,531	-	170,000	-
	734,285	32,483	1,673,240	285,235	624,000	1,885,201
Net Income	$ 2,118,122	$ 207,519	$ 4,645,967	$ 773,875	$ 563,782	$ 3,104,317

Income Statement For the year ended December 31, 2010	Ottawa River Power Corporation	Parry Sound Power Corporation	Peterborough Distribution Incorporated	Port Colborne Hydro Inc.	PowerStream Inc.	PUC Distribution Inc.
Power and Distribution Revenue	$ 18,833,859	$ 9,094,470	$ 79,505,559	$ 21,751,508	$ 854,489,906	$ 68,491,560
Cost of Power and Related Costs	15,149,078	7,257,356	64,275,503	16,240,473	691,318,413	53,271,668
	3,684,781	1,837,114	15,230,056	5,511,035	163,171,493	15,219,892
Other Income	172,913	10,018	1,578,873	(807,846)	556,917	598,940
Expenses						
Operating	388,095	70,690	1,688,112	407,031	10,831,471	2,952,709
Maintenance	491,364	219,988	1,211,448	545,428	8,489,558	2,141,267
Administrative	1,442,856	922,570	3,466,199	2,535,233	36,673,098	3,593,608
Other	3,000	-	954,940	71,629	10,588,616	50,944
Depreciation and Amortization	733,721	372,063	3,325,168	451,923	46,255,096	3,207,749
Financing	447,369	190,032	2,440,831	518,795	24,043,616	1,662,903
	3,506,404	1,775,343	13,086,697	4,530,039	136,881,455	13,609,180
Net Income Before Taxes	351,289	71,788	3,722,232	173,149	26,846,955	2,209,652
PILs and Income Taxes						
Current	29,695	(27,051)	1,217,103	27,047	-	28,000
Future	-	-	-	-	380,062	417,000
	29,695	(27,051)	1,217,103	27,047	380,062	445,000
Net Income	$ 321,594	$ 98,839	$ 2,505,129	$ 146,102	$ 26,466,893	$ 1,764,652

Income Statement For the year ended December 31, 2010	Renfrew Hydro Inc.	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.	Tillsonburg Hydro Inc.
Power and Distribution Revenue	$ 10,030,796	$ 11,315,053	$ 7,042,572	$ 31,407,435	$ 96,221,622	$ 18,724,253
Cost of Power and Related Costs	8,402,755	9,130,052	5,202,374	24,923,732	78,449,275	15,397,529
	1,628,041	2,185,000	1,840,197	6,483,703	17,772,347	3,326,724
Other Income	55,737	42,440	33,600	99,547	449,744	85,336
Expenses						
Operating	198,937	178,302	493,191	677,862	3,069,580	907,140
Maintenance	163,008	346,408	116,678	408,347	3,413,044	170,839
Administrative	679,154	1,120,111	563,578	2,250,550	5,829,733	1,134,493
Other	-	21,558	-	114,870	61,000	-
Depreciation and Amortization	380,171	260,560	280,606	1,340,883	4,686,212	653,359
Financing	217,172	100,180	110,436	848,193	436,729	10,049
	1,638,442	2,027,120	1,564,489	5,640,705	17,496,299	2,875,880
Net Income Before Taxes	45,337	200,320	309,309	942,544	725,793	536,179
PILs and Income Taxes						
Current	6,960	(1,415)	12,409	407,060	580,000	83,488
Future	-	-	-	-	(326,500)	-
	6,960	(1,415)	12,409	407,060	253,500	83,488
Net Income	$ 38,377	$ 201,735	$ 296,900	$ 535,485	$ 472,293	$ 452,691

Income Statement For the year ended December 31, 2010	Toronto Hydro-Electric System Limited	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.	Wellington North Power Inc.
Power and Distribution Revenue	$ 2,315,553,094	$ 257,626,029	$ 14,179,168	$ 141,743,447	$ 44,917,894	$ 9,989,881
Cost of Power and Related Costs	1,788,678,600	208,748,097	10,198,569	115,754,477	35,898,028	8,114,880
	526,874,494	48,877,932	3,980,599	25,988,970	9,019,866	1,875,002
Other Income	14,820,243	1,505,869	37,138	1,004,282	116,119	71,131
Expenses						
Operating	50,904,671	4,154,019	23,217	3,599,586	1,297,663	239,492
Maintenance	48,919,166	2,435,342	487,145	1,422,561	932,588	182,571
Administrative	110,514,032	13,956,151	1,667,677	4,877,937	2,503,075	838,811
Other	8,149,308	23,474	25,004	267,084	65,416	11,769
Depreciation and Amortization	164,959,438	13,135,497	621,954	7,332,020	1,870,111	375,910
Financing	69,449,174	5,389,818	218,876	2,923,580	981,337	92,107
	452,895,790	39,094,301	3,043,873	20,422,769	7,650,190	1,740,661
Net Income Before Taxes	88,798,947	11,289,500	973,863	6,570,483	1,485,795	205,472
PILs and Income Taxes						
Current	23,945,794	3,249,262	247,119	1,189,851	503,422	3,867
Future	-	-	(56,543)	-	-	-
	23,945,794	3,249,262	190,576	1,189,851	503,422	3,867
Net Income	$ 64,853,153	$ 8,040,238	$ 783,287	$ 5,380,632	$ 982,373	$ 201,605

Income Statement For the year ended December 31, 2010	West Coast Huron Energy Inc.	West Perth Power Inc.	Westario Power Inc.	Whitby Hydro Electric Corporation	Woodstock Hydro Services Inc.	Total Industry
Power and Distribution Revenue	$ 9,512,407	$ 5,859,686	$ 45,755,798	$ 79,786,971	$ 30,834,015	$ 12,839,252,356
Cost of Power and Related Costs	7,251,608	4,982,335	36,625,253	60,752,605	24,104,539	9,786,532,663
	2,260,799	877,351	9,130,546	19,034,366	6,729,476	3,052,719,693
Other Income	73,890	121,070	232,304	427,063	246,067	90,923,551
Expenses						
Operating	217,126	68,320	213,163	1,973,079	763,741	258,866,440
Maintenance	108,554	45,440	1,236,423	1,652,115	602,881	373,860,732
Administrative	999,395	856,041	2,844,734	5,240,406	2,170,969	717,915,492
Other	-	892	115,227	-	132,225	38,586,212
Depreciation and Amortization	258,314	221,456	1,855,324	4,484,854	1,857,654	804,634,237
Financing	81,405	99,808	976,798	2,121,509	689,793	371,411,032
	1,664,794	1,291,956	7,241,668	15,471,963	6,217,263	2,565,274,145
Net Income Before Taxes	669,895	(293,536)	2,121,182	3,989,467	758,280	578,369,100
PILs and Income Taxes						
Current	127,852	-	478,000	1,481,096	338,426	105,448,578
Future	-	-	(175,000)	-	175,310	814,261
	127,852	-	303,000	1,481,096	513,736	106,262,839
Net Income	$ 542,043	$ (293,536)	$ 1,818,182	$ 2,508,371	$ 244,544	$ 472,106,260

Financial Ratios For the year ended December 31, 2010	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brant County Power Inc.	Brantford Power Inc.	Burlington Hydro Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	2.22	1.88	1.52	1.69	2.01	1.53
Leverage Ratios						
Debt Ratio (Long Term Debt/Total Assets)	55%	59%	33%	24%	42%	32%
Debt to Equity Ratio (Long Term Debt/Total Equity)	1.47	2.21	1.07	0.41	1.22	0.81
Interest Coverage (EBIT/Interest Charges)	1.60	0.90	3.80	4.45	2.68	2.83
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	1.57%	1.76%	4.60%	3.16%	1.91%	3.16%
Financial Statement Return on Equity (Net Income/Total Equity)	4.17%	6.63%	14.97%	5.55%	5.58%	7.95%

Financial Ratios For the year ended December 31, 2010	Cambridge and North Dumfries Hydro Inc.	Canadian Niagara Power Inc.	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	Chatham-Kent Hydro Inc.	Clinton Power Corporation
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	2.39	0.77	3.72	2.60	1.40	0.54
Leverage Ratios						
Debt Ratio (Long Term Debt/Total Assets)	30%	52%	34%	0%	43%	0%
Debt to Equity Ratio (Long Term Debt/Total Equity)	0.66	2.68	0.77	0.00	1.31	0.00
Interest Coverage (EBIT/Interest Charges)	4.43	1.80	1.52	22.64	3.00	-0.17
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	3.71%	2.11%	2.15%	2.90%	3.17%	-2.88%
Financial Statement Return on Equity (Net Income/Total Equity)	8.06%	10.92%	4.86%	3.67%	9.60%	-20.44%

Financial Ratios **For the year ended** **December 31, 2010**	COLLUS Power Corporation	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Enersource Hydro Mississauga Inc.	EnWin Utilities Ltd.	Erie Thames Powerlines Corporation
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	1.43	2.88	1.53	1.60	0.73	0.79
Leverage Ratios						
Debt Ratio (Long Term Debt/Total Assets)	18%	0%	31%	46%	21%	28%
Debt to Equity Ratio (Long Term Debt/Total Equity)	0.41	0.00	0.97	1.39	0.59	0.99
Interest Coverage (EBIT/Interest Charges)	2.98	248.07	7.06	2.05	4.38	2.20
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	1.60%	2.53%	5.07%	2.02%	4.83%	1.76%
Financial Statement Return on Equity (Net Income/Total Equity)	3.70%	3.11%	15.95%	6.13%	13.31%	6.24%

Financial Ratios For the year ended December 31, 2010	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.	Grimsby Power Incorporated
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	1.08	1.09	0.48	4.11	0.45	1.73
Leverage Ratios						
Debt Ratio (Long Term Debt/Total Assets)	27%	33%	5%	0%	0%	43%
Debt to Equity Ratio (Long Term Debt/Total Equity)	0.92	1.08	0.12	0.00	0.00	1.18
Interest Coverage (EBIT/Interest Charges)	1.38	2.96	2.91	2.19	2.40	1.98
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	0.42%	3.59%	3.40%	0.19%	4.50%	1.59%
Financial Statement Return on Equity (Net Income/Total Equity)	1.46%	11.61%	8.50%	0.30%	34.12%	4.40%

Financial Ratios For the year ended December 31, 2010	Guelph Hydro Electric Systems Inc.	Haldimand County Hydro Inc.	Halton Hills Hydro Inc.	Hearst Power Distribution Company Limited	Horizon Utilities Corporation	Hydro 2000 Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	3.00	1.48	1.15	3.86	1.11	1.78
Leverage Ratios						
Debt Ratio (Long Term Debt/Total Assets)	44%	17%	32%	25%	35%	15%
Debt to Equity Ratio (Long Term Debt/Total Equity)	1.38	0.27	0.75	0.59	0.87	0.26
Interest Coverage (EBIT/Interest Charges)	3.20	8.13	2.75	0.80	2.86	-0.73
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	2.81%	5.48%	2.63%	0.09%	2.63%	-2.15%
Financial Statement Return on Equity (Net Income/Total Equity)	8.71%	8.54%	6.18%	0.22%	6.63%	-3.85%

Financial Ratios For the year ended December 31, 2010	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.	Hydro Ottawa Limited	Innisfil Hydro Distribution Systems Limited	Kenora Hydro Electric Corporation Ltd.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	1.69	0.75	1.05	1.45	0.65	1.80
Leverage Ratios						
Debt Ratio (Long Term Debt/Total Assets)	7%	41%	43%	44%	16%	37%
Debt to Equity Ratio (Long Term Debt/Total Equity)	0.18	1.29	1.35	1.22	0.36	0.84
Interest Coverage (EBIT/Interest Charges)	5.23	2.84	2.45	3.51	3.83	1.38
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	2.19%	3.81%	3.09%	3.75%	2.62%	0.41%
Financial Statement Return on Equity (Net Income/Total Equity)	5.41%	11.89%	9.81%	10.33%	5.87%	0.92%

Financial Ratios For the year ended December 31, 2010	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	London Hydro Inc.	Middlesex Power Distribution Corporation
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	1.24	2.39	3.13	0.86	1.47	1.42
Leverage Ratios						
Debt Ratio (Long Term Debt/Total Assets)	26%	38%	48%	16%	33%	38%
Debt to Equity Ratio (Long Term Debt/Total Equity)	0.67	0.85	1.31	0.29	0.76	1.24
Interest Coverage (EBIT/Interest Charges)	1.80	2.96	2.56	5.02	3.37	2.76
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	1.06%	3.46%	2.77%	3.68%	3.25%	3.14%
Financial Statement Return on Equity (Net Income/Total Equity)	2.71%	7.67%	7.58%	6.64%	7.59%	10.20%

Financial Ratios For the year ended December 31, 2010	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket - Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.	Norfolk Power Distribution Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	0.82	1.64	3.34	1.57	0.71	1.47
Leverage Ratios						
Debt Ratio (Long Term Debt/Total Assets)	13%	31%	35%	25%	26%	42%
Debt to Equity Ratio (Long Term Debt/Total Equity)	0.24	0.71	0.65	0.49	0.58	0.96
Interest Coverage (EBIT/Interest Charges)	8.06	4.22	2.95	2.53	2.54	2.83
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	4.68%	5.24%	2.80%	1.64%	2.69%	3.19%
Financial Statement Return on Equity (Net Income/Total Equity)	8.67%	12.15%	5.30%	3.18%	5.96%	7.23%

Financial Ratios **For the year ended** **December 31, 2010**	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation	Oshawa PUC Networks Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	2.44	1.94	1.12	1.83	1.78	2.70
Leverage Ratios						
Debt Ratio (Long Term Debt/Total Assets)	37%	29%	40%	34%	41%	33%
Debt to Equity Ratio (Long Term Debt/Total Equity)	0.90	0.65	1.88	0.80	1.21	0.92
Interest Coverage (EBIT/Interest Charges)	3.77	2.94	2.16	3.57	2.73	3.44
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	3.49%	2.66%	2.51%	3.50%	1.98%	3.42%
Financial Statement Return on Equity (Net Income/Total Equity)	8.54%	6.05%	11.70%	8.34%	5.83%	9.46%

Financial Ratios For the year ended December 31, 2010	Ottawa River Power Corporation	Parry Sound Power Corporation	Peterborough Distribution Incorporated	Port Colborne Hydro Inc.	PowerStream Inc.	PUC Distribution Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	3.29	1.05	3.64	0.20	1.02	2.07
Leverage Ratios						
Debt Ratio (Long Term Debt/Total Assets)	25%	32%	59%	0%	39%	48%
Debt to Equity Ratio (Long Term Debt/Total Equity)	0.74	1.01	2.14	0.00	1.24	1.53
Interest Coverage (EBIT/Interest Charges)	1.79	1.38	2.52	1.33	2.12	2.33
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	1.46%	1.29%	2.45%	0.77%	2.88%	2.69%
Financial Statement Return on Equity (Net Income/Total Equity)	4.26%	4.09%	8.86%	0.00%	9.23%	8.57%

Financial Ratios For the year ended December 31, 2010	Renfrew Hydro Inc.	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.	Tillsonburg Hydro Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	3.67	1.77	0.66	1.51	3.68	2.24
Leverage Ratios						
Debt Ratio (Long Term Debt/Total Assets)	35%	31%	0%	36%	43%	9%
Debt to Equity Ratio (Long Term Debt/Total Equity)	0.89	0.68	0.00	0.83	0.90	0.13
Interest Coverage (EBIT/Interest Charges)	1.21	3.00	3.80	2.11	2.66	54.36
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	0.46%	2.57%	3.67%	1.88%	0.50%	3.58%
Financial Statement Return on Equity (Net Income/Total Equity)	1.18%	5.68%	10.02%	4.34%	1.04%	5.15%

Financial Ratios For the year ended December 31, 2010	Toronto Hydro-Electric System Limited	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.	Wellington North Power Inc.
Liquidity Ratios						
Current Ratio (Current Assets/Current Liabilities)	1.05	1.07	3.46	0.94	2.66	1.18
Leverage Ratios						
Debt Ratio (Long Term Debt/Total Assets)	39%	35%	20%	28%	41%	26%
Debt to Equity Ratio (Long Term Debt/Total Equity)	1.24	1.13	0.38	0.67	1.26	0.74
Interest Coverage (EBIT/Interest Charges)	2.28	3.09	5.45	3.25	2.51	3.23
Profitability Ratios						
Financial Statement Return on Assets (Net Income/Total Assets)	2.28%	3.41%	4.45%	3.39%	2.37%	2.64%
Financial Statement Return on Equity (Net Income/Total Equity)	7.26%	11.01%	8.34%	7.96%	7.19%	7.62%

Financial Ratios For the year ended December 31, 2010	West Coast Huron Energy Inc.	West Perth Power Inc.	Westario Power Inc.	Whitby Hydro Electric Corporation	Woodstock Hydro Services Inc.
Liquidity Ratios					
Current Ratio (Current Assets/Current Liabilities)	2.87	2.53	2.02	1.56	2.04
Leverage Ratios					
Debt Ratio (Long Term Debt/Total Assets)	15%	23%	32%	32%	35%
Debt to Equity Ratio (Long Term Debt/Total Equity)	0.22	0.80	0.62	0.65	0.88
Interest Coverage (EBIT/Interest Charges)	9.23	-1.94	3.17	2.88	2.10
Profitability Ratios					
Financial Statement Return on Assets (Net Income/Total Assets)	8.14%	-5.72%	3.76%	2.87%	0.68%
Financial Statement Return on Equity (Net Income/Total Equity)	11.96%	-19.95%	7.28%	5.76%	1.70%

General Statistics For the year ended December 31, 2010	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brant County Power Inc.	Brantford Power Inc.	Burlington Hydro Inc.
Population Served	16,789	3,000	84,379	25,000	94,493	175,800
Municipal Population	10,552	3,000	86,689	30,000	94,493	175,800
Seasonal Population	3,565	0	0	0	0	0
Residential	10,623	1,409	31,750	8,215	34,495	58,263
General Service (<50kW)	946	232	3,511	1,337	2,735	5,045
General Service (50-4999kW)	35	22	424	115	424	1,021
Large User (>5000kW)	8	0	3	0	0	0
Sub Transmission	0	0	0	0	0	0
Total Customers	11,612	1,663	35,688	9,667	37,654	64,329
Rural Service Area (sq km)	14,197	0	147	254	0	90
Urban Service Area (sq km)	3	380	54	4	74	98
Total Service Area (sq km)	14,200	380	201	258	74	188
Overhead km of Line	1,844	92	574	282	266	886
Underground km of Line	4	0	178	38	242	841
Total km of Line	1,848	92	752	320	508	1,727
Total kWh Delivered (excluding losses)	181,305,270	22,577,569	1,042,583,478	277,058,211	920,628,448	1,646,383,976
Total Distribution Losses (kWh)	19,179,237	2,131,453	35,500,358	14,374,849	30,130,665	62,561,789
Total kWh Purchased	200,484,507	24,709,022	1,078,083,836	291,433,060	950,759,113	1,708,945,765
Winter Peak (kW)	39,570	4,622	141,970	44,355	152,255	273,536
Summer Peak (kW)	27,678	4,103	188,562	46,817	189,600	364,929
Average Peak (kW)	29,484	3,922	123,750	42,630	152,836	284,725
Capital Additions in 2010	$ 10,550,826	$ 364,194	$ 8,145,961	$ 1,686,246	$ 6,277,461	$ 12,495,314

General Statistics For the year ended December 31, 2010	Cambridge and North Dumfries Hydro Inc.	Canadian Niagara Power Inc.	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	Chatham-Kent Hydro Inc.	Clinton Power Corporation
Population Served	138,810	27,698	21,640	2,428	94,769	3,100
Municipal Population	138,810	27,698	28,530	2,428	107,615	3,100
Seasonal Population	0	0	0	3	0	0
Residential	45,526	14,278	5,692	1,132	28,512	1,403
General Service (<50kW)	4,627	1,232	709	160	3,118	217
General Service (50-4999kW)	735	125	62	14	402	19
Large User (>5000kW)	2	0	0	0	1	0
Sub Transmission	0	0	0	0	0	0
Total Customers	50,890	15,635	6,463	1,306	32,033	1,639
Rural Service Area (sq km)	213	133	0	0	0	0
Urban Service Area (sq km)	90	35	10	2	70	4
Total Service Area (sq km)	303	168	10	2	70	4
Overhead km of Line	708	482	78	26	599	17
Underground km of Line	403	45	69	1	284	4
Total km of Line	1,111	527	147	27	883	21
Total kWh Delivered (excluding losses)	1,472,568,583	282,006,980	148,965,400	26,167,966	720,716,470	29,771,306
Total Distribution Losses (kWh)	40,597,220	14,443,896	6,967,675	1,741,735	28,385,740	759,173
Total kWh Purchased	1,513,165,803	296,450,876	155,933,075	27,909,701	749,102,210	30,530,479
Winter Peak (kW)	241,182	46,300	26,855	6,531	112,418	1,581
Summer Peak (kW)	302,537	56,200	27,922	4,156	155,132	1,215
Average Peak (kW)	246,993	42,300	25,229	4,430	120,387	1,067
Capital Additions in 2010	$ 11,483,571	$ 4,277,982	$ 556,470	$ 9,517	$ 6,391,579	$ 340,697

General Statistics For the year ended December 31, 2010	COLLUS Power Corporation	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Eastern Ontario Power Inc.	Enersource Hydro Mississauga Inc.	EnWin Utilities Ltd.
Population Served	27,000	4,000	21,873	6,700	734,000	215,718
Municipal Population	27,000	12,500	74,185	5,000	734,000	216,473
Seasonal Population	0	0	1	200	0	0
Residential	13,727	1,777	9,899	3,100	171,247	76,720
General Service (<50kW)	1,687	170	1,187	438	17,197	6,955
General Service (50-4999kW)	119	11	119	23	4,506	1,181
Large User (>5000kW)	0	0	0	0	10	10
Sub Transmission	0	0	0	0	0	0
Total Customers	15,533	1,958	11,205	**3,561**	192,960	84,866
Rural Service Area (sq km)	0	0	0	48	0	0
Urban Service Area (sq km)	57	5	22	18	287	120
Total Service Area (sq km)	57	5	22	66	287	120
Overhead km of Line	211	15	89	167	1,807	713
Underground km of Line	128	12	60	10	3,360	466
Total km of Line	339	27	149	177	5,167	1,179
Total kWh Delivered (excluding losses)	313,057,702	29,135,811	238,626,027	59,196,201	7,708,674,748	2,585,491,563
Total Distribution Losses (kWh)	10,014,550	934,570	22,658,881	7,160,213	240,470,883	76,417,483
Total kWh Purchased	323,072,252	30,070,381	261,284,908	66,356,414	7,949,145,631	2,661,909,047
Winter Peak (kW)	57,125	6,862	53,821	12,100	1,179,415	390,400
Summer Peak (kW)	51,307	6,052	62,277	11,400	1,546,600	517,600
Average Peak (kW)	48,942	5,680	47,798	10,500	1,245,655	412,217
Capital Additions in 2010	$ 2,074,828	$ 196,476	$ 810,311	$ 924,935	$ 49,993,549	$ 18,549,731

General Statistics For the year ended December 31, 2010	Erie Thames Powerlines Corporation	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.
Population Served	32,042	7,138	73,654	44,187	8,315	109,529
Municipal Population	35,246	8,700	105,220	44,187	8,315	170,219
Seasonal Population	235	65	0	0	0	142
Residential	12,847	2,850	25,915	17,373	3,307	42,068
General Service (<50kW)	1,378	425	2,046	1,985	419	4,118
General Service (50-4999kW)	146	25	222	220	51	524
Large User (>5000kW)	2	0	0	1	0	0
Sub Transmission	0	0	0	0	0	0
Total Customers	14,373	3,300	28,183	19,579	3,777	46,710
Rural Service Area (sq km)	1,830	73	38	0	0	120
Urban Service Area (sq km)	47	26	66	44	26	290
Total Service Area (sq km)	1,877	99	104	44	26	410
Overhead km of Line	212	126	217	185	76	731
Underground km of Line	58	11	259	92	8	213
Total km of Line	270	137	476	277	84	944
Total kWh Delivered (excluding losses)	417,666,443	61,011,020	562,667,302	572,326,732	79,739,754	930,392,978
Total Distribution Losses (kWh)	13,167,175	2,849,989	19,402,984	16,434,050	4,308,017	44,656,989
Total kWh Purchased	430,833,619	63,861,009	582,070,286	588,760,782	84,047,771	975,049,967
Winter Peak (kW)	79,525	13,449	88,536	94,400	18,000	206,940
Summer Peak (kW)	74,461	9,350	143,420	103,100	13,893	154,643
Average Peak (kW)	67,026	10,212	100,033	91,920	13,223	157,619
Capital Additions in 2010	$ 1,463,896	$ 565,821	$ 8,851,455	$ 4,060,804	$ 522,282	$ 8,359,149

General Statistics For the year ended December 31, 2010	Grimsby Power Incorporated	Guelph Hydro Electric Systems Inc.	Haldimand County Hydro Inc.	Halton Hills Hydro Inc.	Hearst Power Distribution Company Limited	Horizon Utilities Corporation
Population Served	27,000	131,605	45,212	55,089	5,620	574,299
Municipal Population	27,000	131,605	45,212	55,289	5,620	660,108
Seasonal Population	0	0	0	0	0	0
Residential	9,379	46,001	18,465	18,944	2,292	214,133
General Service (<50kW)	662	3,647	2,369	1,655	401	18,053
General Service (50-4999kW)	110	598	137	191	41	2,265
Large User (>5000kW)	0	4	0	0	0	13
Sub Transmission	0	0	0	0	0	0
Total Customers	10,151	50,250	20,971	20,790	2,734	234,464
Rural Service Area (sq km)	45	0	1,216	225	0	88
Urban Service Area (sq km)	22	93	36	26	93	338
Total Service Area (sq km)	67	93	1,252	251	93	426
Overhead km of Line	173	427	1,634	859	57	1,543
Underground km of Line	68	638	89	545	11	1,872
Total km of Line	241	1,065	1,723	1,404	68	3,415
Total kWh Delivered (excluding losses)	179,605,826	1,626,355,690	457,442,011	490,643,422	73,847,934	5,696,035,217
Total Distribution Losses (kWh)	9,339,452	14,641,705	24,221,610	29,957,399	3,750,470	160,328,694
Total kWh Purchased	188,945,278	1,640,997,395	481,663,621	520,600,821	77,598,404	5,856,363,911
Winter Peak (kW)	31,678	253,725	95,666	87,789	16,576	847,591
Summer Peak (kW)	57,081	285,955	98,223	107,148	13,283	1,091,173
Average Peak (kW)	35,796	251,630	83,121	58,735	13,181	888,654
Capital Additions in 2010	$ 1,459,002	$ 18,997,225	$ 3,244,476	$ 3,124,995	$ 46,591	$ 38,802,211

General Statistics For the year ended December 31, 2010	Hydro 2000 Inc.	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.	Hydro Ottawa Limited	Innisfil Hydro Distribution Systems Limited
Population Served	2,650	10,500	498,615	3,010,854	825,813	34,000
Municipal Population	9,500	10,500	498,615	3,010,854	917,570	34,000
Seasonal Population	0	0	0	156,243	0	832
Residential	1,041	4,817	124,592	1,093,342	273,758	13,747
General Service (<50kW)	143	593	7,975	101,638	23,548	892
General Service (50-4999kW)	12	86	1,655	7,628	3,346	68
Large User (>5000kW)	0	0	6	0	12	0
Sub Transmission	0	0	0	422	0	0
Total Customers	1,196	5,496	134,228	1,203,030	300,664	14,707
Rural Service Area (sq km)	0	0	0	650,000	650	221
Urban Service Area (sq km)	9	8	269	0	454	292
Total Service Area (sq km)	9	8	269	650,000	1,104	513
Overhead km of Line	18	56	806	116,656	2,693	613
Underground km of Line	3	10	2,017	4,265	2,721	140
Total km of Line	21	66	2,823	120,921	5,414	753
Total kWh Delivered (excluding losses)	23,153,118	152,090,908	3,777,080,877	23,408,000,000	7,594,977,085	231,788,047
Total Distribution Losses (kWh)	2,295,868	6,321,803	133,980,187	1,738,000,000	244,784,071	12,247,033
Total kWh Purchased	25,448,986	158,412,711	3,911,061,064	25,146,000,000	7,839,761,156	244,035,080
Winter Peak (kW)	6,133	30,183	606,690	4,180,551	1,239,498	51,327
Summer Peak (kW)	3,665	26,499	799,130	3,479,473	1,518,168	49,647
Average Peak (kW)	4,170	25,613	631,114	3,210,827	1,228,007	44,322
Capital Additions in 2010	$ 70,216	$ 226,655	$ 35,696,631	$ 692,133,158	$ 89,489,040	$ 4,945,828

General Statistics For the year ended December 31, 2010	Kenora Hydro Electric Corporation Ltd.	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	London Hydro Inc.
Population Served	12,000	58,000	248,760	22,000	22,769	355,000
Municipal Population	16,500	119,000	248,760	22,000	36,889	355,000
Seasonal Population	0	0	0	0	195	0
Residential	4,770	23,336	78,142	8,369	7,782	133,452
General Service (<50kW)	741	3,264	7,493	1,069	1,556	11,897
General Service (50-4999kW)	69	341	975	133	101	1,621
Large User (>5000kW)	0	3	1	0	0	4
Sub Transmission	0	0	0	0	0	0
Total Customers	5,580	26,944	86,611	9,571	9,439	146,974
Rural Service Area (sq km)	0	0	280	0	128	258
Urban Service Area (sq km)	24	32	124	27	16	163
Total Service Area (sq km)	24	32	404	27	144	421
Overhead km of Line	88	233	1,042	95	288	1,364
Underground km of Line	10	128	824	20	67	1,410
Total km of Line	98	361	1,866	115	355	2,774
Total kWh Delivered (excluding losses)	105,584,412	715,855,323	1,829,523,206	247,158,146	203,653,096	3,376,719,308
Total Distribution Losses (kWh)	3,938,502	15,794,501	66,665,709	14,007,443	13,347,061	51,442,093
Total kWh Purchased	109,522,914	731,649,824	1,896,188,915	261,165,589	217,000,157	3,428,161,401
Winter Peak (kW)	21,034	125,098	306,685	44,096	39,610	516,721
Summer Peak (kW)	18,403	119,546	367,988	45,140	37,000	687,625
Average Peak (kW)	17,198	112,901	304,495	40,886	34,201	545,926
Capital Additions in 2010	$ 957,477	$ 3,679,058	$ 20,832,224	$ 2,047,721	$ 2,454,579	$ 26,572,150

General Statistics For the year ended December 31, 2010	Middlesex Power Distribution Corporation	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket - Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.
Population Served	7,831	16,000	87,000	91,092	138,450	15,000
Municipal Population	21,749	17,000	87,000	136,686	139,368	15,000
Seasonal Population	0	0	0	525	0	250
Residential	6,984	6,063	26,587	29,533	45,840	6,537
General Service (<50kW)	779	738	2,283	2,973	4,357	1,224
General Service (50-4999kW)	95	113	270	405	851	121
Large User (>5000kW)	1	0	2	0	0	0
Sub Transmission	0	0	0	0	0	0
Total Customers	7,859	6,914	29,142	32,911	51,048	7,882
Rural Service Area (sq km)	0	0	313	3	759	119
Urban Service Area (sq km)	26	20	57	71	68	14
Total Service Area (sq km)	26	20	370	74	827	133
Overhead km of Line	99	111	576	589	1,471	241
Underground km of Line	26	38	362	482	479	101
Total km of Line	125	149	938	1,071	1,950	342
Total kWh Delivered (excluding losses)	211,490,123	207,341,771	728,497,481	687,144,747	1,193,712,076	178,008,612
Total Distribution Losses (kWh)	10,550,916	6,196,613	24,176,644	29,883,843	65,874,515	8,268,355
Total kWh Purchased	222,041,039	213,538,384	752,674,125	717,028,590	1,259,586,591	186,276,967
Winter Peak (kW)	33,790	35,827	122,227	120,634	196,717	30,132
Summer Peak (kW)	43,268	40,302	147,307	154,388	261,045	42,306
Average Peak (kW)	34,966	34,743	121,227	118,447	202,194	30,859
Capital Additions in 2010	$ 1,070,547	$ 2,106,073	$ 13,675,457	$ 5,457,928	$ 14,573,700	$ 1,827,387

General Statistics For the year ended December 31, 2010	Norfolk Power Distribution Inc.	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation
Population Served	31,500	55,000	14,000	180,500	29,905	31,000
Municipal Population	63,000	55,000	18,777	180,500	31,149	31,000
Seasonal Population	200	0	0	0	0	0
Residential	16,769	20,845	5,202	56,902	9,963	11,357
General Service (<50kW)	2,009	2,636	755	4,886	1,163	1,344
General Service (50-4999kW)	162	273	69	886	130	161
Large User (>5000kW)	0	0	0	0	0	0
Sub Transmission	0	0	0	0	0	0
Total Customers	18,940	23,754	6,026	62,674	11,256	12,862
Rural Service Area (sq km)	549	279	0	41	0	0
Urban Service Area (sq km)	144	51	28	102	17	27
Total Service Area (sq km)	693	330	28	143	17	27
Overhead km of Line	660	514	365	553	103	248
Underground km of Line	108	97	5	886	73	65
Total km of Line	768	611	370	1,439	176	313
Total kWh Delivered (excluding losses)	368,751,207	566,701,788	123,364,740	1,535,802,202	247,977,784	309,110,743
Total Distribution Losses (kWh)	19,237,611	25,412,533	7,513,694	62,901,468	9,349,118	10,916,337
Total kWh Purchased	387,988,818	592,114,321	130,878,434	1,598,703,670	257,326,902	320,027,080
Winter Peak (kW)	85,057	109,866	23,892	258,870	43,609	57,908
Summer Peak (kW)	87,941	93,148	22,022	354,830	47,841	55,679
Average Peak (kW)	67,063	91,490	21,015	271,682	41,559	50,620
Capital Additions in 2010	$ 4,253,108	$ 6,991,021	$ 459,332	$ 29,692,304	$ 1,605,285	$ 1,469,917

General Statistics For the year ended December 31, 2010	Oshawa PUC Networks Inc.	Ottawa River Power Corporation	Parry Sound Power Corporation	Peterborough Distribution Incorporated	Port Colborne Hydro Inc.	PowerStream Inc.
Population Served	155,000	20,200	6,500	83,396	18,003	1,196,983
Municipal Population	155,000	20,200	6,500	83,396	18,003	1,196,983
Seasonal Population	0	0	0	0	0	0
Residential	48,387	8,955	2,773	31,037	8,151	290,951
General Service (<50kW)	3,795	1,372	538	3,588	937	30,076
General Service (50-4999kW)	527	148	66	385	81	4,512
Large User (>5000kW)	1	0	0	2	0	1
Sub Transmission	0	0	0	0	0	0
Total Customers	52,710	10,475	3,377	35,012	9,169	325,540
Rural Service Area (sq km)	78	0	0	0	103	303
Urban Service Area (sq km)	71	35	15	63	20	503
Total Service Area (sq km)	149	35	15	63	123	806
Overhead km of Line	562	129	118	384	298	2,551
Underground km of Line	393	19	11	168	17	4,830
Total km of Line	955	148	129	552	315	7,381
Total kWh Delivered (excluding losses)	1,090,938,483	188,245,383	84,789,393	801,058,085	191,474,577	8,334,777,460
Total Distribution Losses (kWh)	57,479,847	8,501,968	2,788,257	36,988,178	11,269,480	313,781,656
Total kWh Purchased	1,148,418,330	196,747,350	87,577,650	838,046,263	202,744,057	8,648,559,116
Winter Peak (kW)	220,115	32,708	17,871	147,722	35,300	1,380,420
Summer Peak (kW)	214,439	33,526	13,004	150,103	48,100	1,895,989
Average Peak (kW)	188,605	27,868	13,840	135,507	35,500	1,447,917
Capital Additions in 2010	$ 6,114,983	$ 1,353,781	$ 620,068	$ 5,443,662	$ 1,305,662	$ 93,102,075

General Statistics For the year ended December 31, 2010	PUC Distribution Inc.	Renfrew Hydro Inc.	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.
Population Served	78,000	7,846	9,900	5,336	36,110	109,972
Municipal Population	75,000	7,846	16,700	5,336	36,110	109,140
Seasonal Population	100	0	0	108	0	0
Residential	29,086	3,654	4,982	2,312	14,538	44,559
General Service (<50kW)	3,349	442	770	394	1,687	4,415
General Service (50-4999kW)	435	59	66	48	194	534
Large User (>5000kW)	0	0	0	0	0	0
Sub Transmission	0	0	0	0	0	0
Total Customers	32,870	4,155	5,818	2,754	16,419	49,508
Rural Service Area (sq km)	284	0	7	530	0	259
Urban Service Area (sq km)	58	13	11	6	33	122
Total Service Area (sq km)	342	13	18	536	33	381
Overhead km of Line	616	53	84	205	158	944
Underground km of Line	117	2	10	6	89	234
Total km of Line	733	55	94	211	247	1,178
Total kWh Delivered (excluding losses)	683,757,862	95,702,324	107,839,547	70,415,620	298,005,675	942,525,340
Total Distribution Losses (kWh)	27,960,639	4,474,552	8,753,154	4,304,222	8,536,204	38,642,017
Total kWh Purchased	711,718,501	100,176,876	116,592,701	74,719,842	306,541,879	981,167,357
Winter Peak (kW)	141,244	17,707	29,160	17,859	50,015	176,768
Summer Peak (kW)	101,492	18,705	32,187	11,303	62,047	155,411
Average Peak (kW)	108,859	16,459	21,989	12,538	50,812	150,088
Capital Additions in 2010	$ 5,838,525	$ 533,251	$ 269,009	$ 384,164	$ 1,517,416	$ 9,704,138

General Statistics For the year ended December 31, 2010	Tillsonburg Hydro Inc.	Toronto Hydro-Electric System Limited	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.
Population Served	15,140	2,503,281	312,571	17,300	156,230	50,331
Municipal Population	15,000	2,503,281	432,459	17,300	156,230	50,331
Seasonal Population	0	0	1,595	1,200	0	0
Residential	5,954	620,501	102,929	11,238	45,863	19,543
General Service (<50kW)	658	66,167	8,578	777	5,385	1,692
General Service (50-4999kW)	88	13,668	1,057	31	665	175
Large User (>5000kW)	0	50	5	0	1	1
Sub Transmission	0	0	0	0	0	0
Total Customers	6,700	700,386	112,569	12,046	51,914	21,411
Rural Service Area (sq km)	3	0	386	8	607	0
Urban Service Area (sq km)	21	630	253	53	65	86
Total Service Area (sq km)	24	630	639	61	672	86
Overhead km of Line	102	4,214	1,274	125	1,059	329
Underground km of Line	54	5,776	1,027	115	488	112
Total km of Line	156	9,990	2,301	240	1,547	441
Total kWh Delivered (excluding losses)	185,242,395	24,746,000,033	2,543,041,714	120,927,004	1,425,236,249	424,292,841
Total Distribution Losses (kWh)	5,908,834	888,505,824	114,883,267	4,380,488	54,435,488	19,320,369
Total kWh Purchased	191,151,229	25,634,505,857	2,657,924,981	125,307,492	1,479,671,737	443,613,210
Winter Peak (kW)	36,361	4,006,799	436,342	25,352	242,686	77,653
Summer Peak (kW)	41,632	4,785,876	509,726	27,340	283,517	96,028
Average Peak (kW)	35,707	4,039,475	420,423	21,364	238,015	79,467
Capital Additions in 2010	$ 689,698	$ 421,245,394	$ 27,840,394	$ 924,613	$ 24,256,601	$ 2,830,865

General Statistics For the year ended December 31, 2010	Wellington North Power Inc.	West Coast Huron Energy Inc.	West Perth Power Inc.	Westario Power Inc.	Whitby Hydro Electric Corporation	Woodstock Hydro Services Inc.
Population Served	7,200	7,251	3,900	47,893	125,000	36,000
Municipal Population	11,500	7,251	9,000	77,847	125,000	38,000
Seasonal Population	0	0	0	0	0	0
Residential	3,095	3,237	1,794	19,301	37,283	13,701
General Service (<50kW)	473	483	235	2,429	1,967	1,170
General Service (50-4999kW)	45	49	20	277	419	203
Large User (>5000kW)	0	1	0	0	0	0
Sub Transmission	0	0	0	0	0	0
Total Customers	3,613	3,770	2,049	22,007	39,669	15,074
Rural Service Area (sq km)	0	0	0	0	81	0
Urban Service Area (sq km)	14	8	6	49	67	29
Total Service Area (sq km)	14	8	6	49	148	29
Overhead km of Line	66	52	25	371	499	155
Underground km of Line	10	13	11	144	552	93
Total km of Line	76	65	36	515	1,051	248
Total kWh Delivered (excluding losses)	96,062,450	139,238,572	59,974,441	447,096,956	864,572,083	374,160,476
Total Distribution Losses (kWh)	6,545,839	3,934,816	2,763,035	23,200,762	39,270,846	15,779,599
Total kWh Purchased	102,608,289	143,173,388	62,737,476	470,297,718	903,842,929	389,940,075
Winter Peak (kW)	17,452	26,132	10,019	89,468	153,366	61,971
Summer Peak (kW)	16,834	25,975	11,100	72,813	191,768	74,659
Average Peak (kW)	16,134	23,838	9,961	73,257	152,499	61,426
Capital Additions in 2010	$ 388,852	$ 505,771	$ 494,107	$ 2,936,522	$ 6,179,404	$ 3,533,636

Unitized Statistics and Service Quality Requirements For the year ended December 31, 2010	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brant County Power Inc.	Brantford Power Inc.	Burlington Hydro Inc.
# of Customers per sq km of Service Area	0.82	4.38	177.55	37.47	508.84	342.18
# of Customers per km of Line	6.28	18.08	47.46	30.21	74.12	37.25
Average Power & Distribution Revenue less Cost of Power & Related Costs						
Per Customer Annually	$ 1,540.93	$ 719.85	$ 545.51	$ 627.11	$ 429.13	$ 468.42
Per Total kWh Purchased	$ 0.089	$ 0.048	$ 0.018	$ 0.021	$ 0.017	$ 0.018
Average Cost of Power & Related Costs						
Per Customer Annually	$ 1,476	$ 1,150	$ 1,774	$ 1,914	$ 2,050	$ 1,792
Per Total kWh Purchased	$ 0.085	$ 0.077	$ 0.059	$ 0.063	$ 0.081	$ 0.067
Avg Monthly kWh Consumed per Customer	1,439	1,238	2,517	2,512	2,104	2,214
Avg Peak (kW) per Customer	2.54	2.36	3.47	4.41	4.06	4.43
OM&A Per Customer	$ 744.69	$ 601.11	$ 287.35	$ 361.27	$ 201.44	$ 217.65
Net Income Per Customer	$ 121.99	$ 40.01	$ 98.01	$ 97.24	$ 49.75	$ 73.24
Net Fixed Assets per Customer	$ 6,067	$ 1,346	$ 1,192	$ 2,027	$ 1,648	$ 1,323
Service Quality Requirements						
Low Voltage Connections (OEB Min. Standard: 90%)	98.60	100.00	100.00	99.00	100.00	96.30
High Voltage Connections (OEB Min. Standard: 90%)	N/A	N/A	100.00	N/A	100.00	N/A
Telephone Accessibility (OEB Min. Standard: 65%)	73.20	100.00	57.90	93.80	71.20	70.70
Appointments Met (OEB Min. Standard: 90%)	100.00	100.00	100.00	100.00	100.00	99.80
Written Response to Enquiries (OEB Min. Standard: 80%)	100.00	96.70	99.90	99.80	99.20	100.00
Emergency Urban Response (OEB Min. Standard: 80%)	N/A	100.00	100.00	100.00	100.00	84.40
Emergency Rural Response (OEB Min. Standard: 80%)	100.00	100.00	100.00	100.00	N/A	N/A
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	N/A	N/A	13.90	2.30	3.80	4.20
Appointments Scheduling (OEB Min. Standard: 90%)	96.00	100.00	100.00	100.00	99.60	100.00
Rescheduling a Missed Appointment: (OEB Standard: 100%)	100.00	N/A	N/A	N/A	100.00	100.00
Service Reliability Indices						
SAIDI-Annual	16.65	0.07	1.75	2.89	1.09	1.13
SAIFI-Annual	4.58	2.02	2.34	2.59	1.95	1.72
CAIDI-Annual	3.64	0.04	0.75	1.11	0.56	0.66
Loss of Supply Adjusted Service Reliability Indices						
SAIDI-Annual	15.86	0.03	1.51	0.48	0.12	1.13
SAIFI-Annual	3.72	0.03	2.11	0.59	0.33	1.72
CAIDI-Annual	4.26	0.94	0.72	0.80	0.37	0.66

N/A -No data reported for 2010.

Unitized Statistics and Service Quality Requirements For the year ended December 31, 2010	Cambridge and North Dumfries Hydro Inc.	Canadian Niagara Power Inc.	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	Chatham-Kent Hydro Inc.	Clinton Power Corporation
# of Customers per sq km of Service Area	167.95	82.03 *	646.30	653.00	457.61	409.75
# of Customers per km of Line	45.81	27.27 *	43.97	48.37	36.28	78.05
Average Power & Distribution Revenue less Cost of Power & Related Costs						
Per Customer Annually	$ 466.22	$ 598.97 *	$ 449.74	$ 484.44	$ 470.64	$ 338.72
Per Total kWh Purchased	$ 0.016	$ 0.032 *	$ 0.019	$ 0.023	$ 0.020	$ 0.018
Average Cost of Power & Related Costs						
Per Customer Annually	$ 2,389	$ 1,531 *	$ 1,724	$ 1,657	$ 1,939	$ 1,326
Per Total kWh Purchased	$ 0.080	$ 0.081 *	$ 0.071	$ 0.078	$ 0.083	$ 0.071
Avg Monthly kWh Consumed per Customer	2,478	1,575 *	2,011	1,781	1,949	1,552
Avg Peak (kW) per Customer	4.85	2.95 *	3.90	3.39	3.76	0.65
OM&A Per Customer	$ 188.26	$ 281.52 *	$ 267.74	$ 412.71	$ 201.96	$ 341.18
Net Income Per Customer	$ 100.71	$ 76.64 *	$ 49.27	$ 47.96	$ 71.50	$ (61.41)
Net Fixed Assets per Customer	$ 1,638	$ 2,673 *	$ 1,007	$ 627	$ 1,512	$ 969
Service Quality Requirements						
Low Voltage Connections (OEB Min. Standard: 90%)	98.50	94.70	100.00	100.00	97.60	100.00
High Voltage Connections (OEB Min. Standard: 90%)	N/A	N/A	100.00	N/A	N/A	N/A
Telephone Accessibility (OEB Min. Standard: 65%)	74.30	85.10	99.80	100.00	67.00	96.70
Appointments Met (OEB Min. Standard: 90%)	99.90	100.00	96.10	100.00	100.00	100.00
Written Response to Enquiries (OEB Min. Standard: 80%)	99.30	100.00	100.00	100.00	100.00	N/A
Emergency Urban Response (OEB Min. Standard: 80%)	98.30	100.00	100.00	100.00	87.90	100.00
Emergency Rural Response (OEB Min. Standard: 80%)	93.00	100.00	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	8.20	2.40	N/A	N/A	1.60	3.10
Appointments Scheduling (OEB Min. Standard: 90%)	100.00	99.50	94.80	100.00	100.00	100.00
Rescheduling a Missed Appointment: (OEB Standard: 100%)	100.00	N/A	100.00	N/A	N/A	N/A
Service Reliability Indices						
SAIDI-Annual	0.97	1.26	2.18	101.68	1.56	0.39
SAIFI-Annual	0.85	2.27	1.67	3.25	1.13	0.72
CAIDI-Annual	1.14	0.56	1.30	31.26	1.38	0.54
Loss of Supply Adjusted Service Reliability Indices						
SAIDI-Annual	0.97	0.90	1.09	1.98	1.33	0.39
SAIFI-Annual	0.85	1.27	0.59	0.92	0.91	0.72
CAIDI-Annual	1.14	0.71	1.86	2.15	1.47	0.54

N/A -No data reported for 2010.

* Includes Eastern Ontario Power Inc.

Unitized Statistics and Service Quality Requirements For the year ended December 31, 2010	COLLUS Power Corporation	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Eastern Ontario Power Inc.	Enersource Hydro Mississauga Inc.	EnWin Utilities Ltd.
# of Customers per sq km of Service Area	272.51	391.60	509.32	*	672.33	707.22
# of Customers per km of Line	45.82	72.52	75.20	*	37.34	71.98
Average Power & Distribution Revenue less Cost of Power & Related Costs						
Per Customer Annually	$ 376.22	$ 365.84	$ 406.46	*	$ 615.66	$ 594.30
Per Total kWh Purchased	$ 0.018	$ 0.024	$ 0.017	*	$ 0.015	$ 0.019
Average Cost of Power & Related Costs						
Per Customer Annually	$ 1,672	$ 1,240	$ 1,405	*	$ 3,118	$ 2,249
Per Total kWh Purchased	$ 0.080	$ 0.081	$ 0.060	*	$ 0.076	$ 0.072
Avg Monthly kWh Consumed per Customer	1,733	1,280	1,943	*	3,433	2,614
Avg Peak (kW) per Customer	3.15	2.90	4.27	*	6.46	4.86
OM&A Per Customer	$ 257.15	$ 241.50	$ 185.93	*	$ 242.63	$ 252.91
Net Income Per Customer	$ 25.67	$ 57.34	$ 105.14	*	$ 66.28	$ 132.94
Net Fixed Assets per Customer	$ 857	$ 982	$ 724	*	$ 2,295	$ 2,156
Service Quality Requirements						
Low Voltage Connections (OEB Min. Standard: 90%)	100.00	100.00	98.30	100.00	99.70	99.30
High Voltage Connections (OEB Min. Standard: 90%)	100.00	N/A	N/A	N/A	100.00	N/A
Telephone Accessibility (OEB Min. Standard: 65%)	97.50	93.50	95.80	91.40	82.00	76.70
Appointments Met (OEB Min. Standard: 90%)	100.00	100.00	100.00	100.00	100.00	99.60
Written Response to Enquiries (OEB Min. Standard: 80%)	100.00	100.00	89.20	100.00	98.40	100.00
Emergency Urban Response (OEB Min. Standard: 80%)	100.00	100.00	80.00	100.00	97.70	96.90
Emergency Rural Response (OEB Min. Standard: 80%)	N/A	N/A	N/A	100.00	N/A	N/A
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	N/A	6.50	0.60	1.40	2.50	3.30
Appointments Scheduling (OEB Min. Standard: 90%)	100.00	100.00	100.00	99.30	97.30	100.00
Rescheduling a Missed Appointment: (OEB Standard: 100%)	N/A	N/A	N/A	N/A	N/A	90.60
Service Reliability Indices						
SAIDI-Annual	1.10	0.02	4.33	7.72	0.58	0.99
SAIFI-Annual	1.03	0.01	1.29	5.45	1.32	1.81
CAIDI-Annual	1.07	2.31	3.35	1.42	0.44	0.55
Loss of Supply Adjusted Service Reliability Indices						
SAIDI-Annual	0.78	-	2.82	2.54	0.55	0.99
SAIFI-Annual	0.83	-	0.95	3.43	1.10	1.81
CAIDI-Annual	0.93	N/A	2.97	0.74	0.50	0.55

N/A -No data reported for 2010.

* Merged with CNPI.

Unitized Statistics and Service Quality Requirements For the year ended December 31, 2010	Erie Thames Powerlines Corporation	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.
# of Customers per sq km of Service Area	7.66	33.33	270.99	444.98	145.27	113.93
# of Customers per km of Line	53.23	24.09	59.21	70.68	44.96	49.48
Average Power & Distribution Revenue less Cost of Power & Related Costs						
Per Customer Annually	$ 457.99	$ 414.32	$ 393.44	$ 501.29	$ 417.41	$ 496.19
Per Total kWh Purchased	$ 0.015	$ 0.021	$ 0.019	$ 0.017	$ 0.019	$ 0.024
Average Cost of Power & Related Costs						
Per Customer Annually	$ 2,288	$ 1,403	$ 1,747	$ 2,427	$ 1,515	$ 1,695
Per Total kWh Purchased	$ 0.076	$ 0.072	$ 0.085	$ 0.081	$ 0.068	$ 0.081
Avg Monthly kWh Consumed per Customer	2,498	1,613	1,721	2,506	1,854	1,740
Avg Peak (kW) per Customer	4.66	3.09	3.55	4.69	3.50	3.37
OM&A Per Customer	$ 308.70	$ 311.73	$ 194.46	$ 203.78	$ 350.99	$ 174.26
Net Income Per Customer	$ 37.44	$ 7.33	$ 69.68	$ 82.08	$ 4.51	$ 101.26
Net Fixed Assets per Customer	$ 1,245	$ 678	$ 1,314	$ 1,712	$ 814	$ 1,401
Service Quality Requirements						
Low Voltage Connections (OEB Min. Standard: 90%)	98.40	100.00	98.60	99.00	100.00	100.00
High Voltage Connections (OEB Min. Standard: 90%)	100.00	N/A	N/A	N/A	100.00	N/A
Telephone Accessibility (OEB Min. Standard: 65%)	81.60	63.90	70.60	98.30	94.00	74.50
Appointments Met (OEB Min. Standard: 90%)	91.90	90.50	94.90	100.00	100.00	100.00
Written Response to Enquiries (OEB Min. Standard: 80%)	100.00	100.00	93.40	100.00	100.00	100.00
Emergency Urban Response (OEB Min. Standard: 80%)	100.00	100.00	100.00	100.00	100.00	98.30
Emergency Rural Response (OEB Min. Standard: 80%)	N/A	N/A	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	2.20	7.60	4.90	1.70	2.80	0.90
Appointments Scheduling (OEB Min. Standard: 90%)	100.00	99.10	97.70	99.70	100.00	100.00
Rescheduling a Missed Appointment: (OEB Standard: 100%)	100.00	N/A	100.00	100.00	N/A	N/A
Service Reliability Indices						
SAIDI-Annual	11.21	1.04	5.82	1.97	0.60	1.10
SAIFI-Annual	4.83	0.28	3.34	2.48	0.31	1.04
CAIDI-Annual	2.32	3.76	1.74	0.80	1.92	1.06
Loss of Supply Adjusted Service Reliability Indices						
SAIDI-Annual	0.92	0.56	3.56	1.86	0.60	0.67
SAIFI-Annual	0.48	0.25	1.65	1.93	0.31	0.84
CAIDI-Annual	1.93	2.27	2.16	0.96	1.92	0.79

N/A -No data reported for 2010.

Unitized Statistics and Service Quality Requirements For the year ended December 31, 2010	Grimsby Power Incorporated	Guelph Hydro Electric Systems Inc.	Haldimand County Hydro Inc.	Halton Hills Hydro Inc.	Hearst Power Distribution Company Limited	Horizon Utilities Corporation
# of Customers per sq km of Service Area	151.51	540.32	16.75	82.83	29.40	550.38
# of Customers per km of Line	42.12	47.18	12.17	14.81	40.21	68.66
Average Power & Distribution Revenue less Cost of Power & Related Costs						
Per Customer Annually	$ 351.82	$ 495.93	$ 649.65	$ 469.46	$ 298.42	$ 382.47
Per Total kWh Purchased	$ 0.019	$ 0.015	$ 0.028	$ 0.019	$ 0.011	$ 0.015
Average Cost of Power & Related Costs						
Per Customer Annually	$ 1,512	$ 2,342	$ 1,785	$ 1,993	$ 2,271	$ 1,763
Per Total kWh Purchased	$ 0.081	$ 0.072	$ 0.078	$ 0.080	$ 0.080	$ 0.071
Avg Monthly kWh Consumed per Customer	1,551	2,721	1,914	2,087	2,365	2,081
Avg Peak (kW) per Customer	3.53	5.01	3.96	2.83	4.82	3.79
OM&A Per Customer	$ 175.41	$ 194.82	$ 325.37	$ 210.67	$ 299.76	$ 165.24
Net Income Per Customer	$ 26.74	$ 81.94	$ 132.96	$ 64.21	$ 2.27	$ 50.48
Net Fixed Assets per Customer	$ 1,114	$ 1,783	$ 1,657	$ 1,448	$ 287	$ 1,420
Service Quality Requirements						
Low Voltage Connections (OEB Min. Standard: 90%)	100.00	99.80	99.20	100.00	100.00	99.70
High Voltage Connections (OEB Min. Standard: 90%)	N/A	100.00	N/A	N/A	N/A	100.00
Telephone Accessibility (OEB Min. Standard: 65%)	72.40	80.00	88.80	86.20	96.70	81.70
Appointments Met (OEB Min. Standard: 90%)	100.00	98.90	98.30	99.20	N/A	96.60
Written Response to Enquiries (OEB Min. Standard: 80%)	100.00	100.00	99.30	100.00	100.00	99.00
Emergency Urban Response (OEB Min. Standard: 80%)	100.00	89.10	95.00	100.00	100.00	95.40
Emergency Rural Response (OEB Min. Standard: 80%)	100.00	N/A	100.00	100.00	N/A	N/A
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	N/A	3.00	2.30	2.00	N/A	2.20
Appointments Scheduling (OEB Min. Standard: 90%)	99.10	98.90	100.00	100.00	100.00	98.70
Rescheduling a Missed Appointment: (OEB Standard: 100%)	100.00	100.00	98.00	100.00	N/A	N/A
Service Reliability Indices						
SAIDI-Annual	3.00	0.39	3.00	1.78	13.87	1.24
SAIFI-Annual	1.06	1.27	1.75	2.75	3.10	1.80
CAIDI-Annual	2.82	0.31	1.71	0.65	4.47	0.69
Loss of Supply Adjusted Service Reliability Indices						
SAIDI-Annual	3.00	0.33	2.77	1.78	1.48	1.15
SAIFI-Annual	1.06	0.75	1.20	2.75	0.76	1.55
CAIDI-Annual	2.82	0.45	2.31	0.65	1.95	0.74

N/A -No data reported for 2010.

Unitized Statistics and Service Quality Requirements For the year ended December 31, 2010	Hydro 2000 Inc.	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.	Hydro Ottawa Limited	Innisfil Hydro Distribution Systems Limited
# of Customers per sq km of Service Area	132.89	687.00	498.99	1.85	272.34	28.67
# of Customers per km of Line	56.95	83.27	47.55	9.95	55.53	19.53
Average Power & Distribution Revenue less Cost of Power & Related Costs						
Per Customer Annually	$ 271.55	$ 241.61	$ 472.43	$ 948.80	$ 493.52	$ 540.77
Per Total kWh Purchased	$ 0.013	$ 0.008	$ 0.016	$ 0.045	$ 0.019	$ 0.033
Average Cost of Power & Related Costs						
Per Customer Annually	$ 1,362	$ 1,860	$ 2,371	$ 1,792	$ 2,062	$ 1,387
Per Total kWh Purchased	$ 0.064	$ 0.065	$ 0.081	$ 0.086	$ 0.079	$ 0.084
Avg Monthly kWh Consumed per Customer	1,773	2,402	2,428	1,742	2,173	1,383
Avg Peak (kW) per Customer	3.49	4.66	4.70	2.67	4.08	3.01
OM&A Per Customer	$ 247.78	$ 157.88	$ 150.37	$ 454.77	$ 183.67	$ 265.75
Net Income Per Customer	$ (22.72)	$ 26.64	$ 97.95	$ 161.23	$ 87.71	$ 62.58
Net Fixed Assets per Customer	$ 373	$ 356	$ 1,928	$ 4,287	$ 1,772	$ 1,537
Service Quality Requirements						
Low Voltage Connections (OEB Min. Standard: 90%)	100.00	97.20	100.00	90.90	100.00	97.10
High Voltage Connections (OEB Min. Standard: 90%)	N/A	100.00	100.00	100.00	100.00	N/A
Telephone Accessibility (OEB Min. Standard: 65%)	99.60	99.90	78.40	72.40	82.10	88.60
Appointments Met (OEB Min. Standard: 90%)	100.00	94.10	100.00	92.70	100.00	84.00
Written Response to Enquiries (OEB Min. Standard: 80%)	100.00	99.70	100.00	99.40	99.90	100.00
Emergency Urban Response (OEB Min. Standard: 80%)	100.00	100.00	100.00	N/A	97.00	N/A
Emergency Rural Response (OEB Min. Standard: 80%)	N/A	N/A	N/A	82.70	N/A	100.00
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	0.40	N/A	2.00	2.60	2.60	11.40
Appointments Scheduling (OEB Min. Standard: 90%)	100.00	99.30	100.00	92.50	100.00	87.00
Rescheduling a Missed Appointment: (OEB Standard: 100%)	N/A	100.00	N/A	98.30	100.00	N/A
Service Reliability Indices						
SAIDI-Annual	3.24	1.17	0.66	9.37	1.36	1.40
SAIFI-Annual	1.40	1.04	1.47	3.25	1.39	1.53
CAIDI-Annual	2.31	1.12	0.45	2.88	0.97	0.91
Loss of Supply Adjusted Service Reliability Indices						
SAIDI-Annual	2.10	1.17	0.46	9.00	1.05	1.34
SAIFI-Annual	0.64	0.90	0.76	2.91	0.77	1.19
CAIDI-Annual	3.29	1.30	0.60	3.09	1.37	1.13

N/A -No data reported for 2010.

Unitized Statistics and Service Quality Requirements For the year ended December 31, 2010	Kenora Hydro Electric Corporation Ltd.	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	London Hydro Inc.
# of Customers per sq km of Service Area	232.50	842.00	214.38	354.48	65.55	349.11
# of Customers per km of Line	56.94	74.64	46.42	83.23	26.59	52.98
Average Power & Distribution Revenue less Cost of Power & Related Costs						
Per Customer Annually	$ 393.23	$ 365.40	$ 423.49	$ 455.42	$ 506.53	$ 421.07
Per Total kWh Purchased	$ 0.020	$ 0.013	$ 0.019	$ 0.017	$ 0.022	$ 0.018
Average Cost of Power & Related Costs						
Per Customer Annually	$ 1,518	$ 2,174	$ 1,812	$ 2,170	$ 1,819	$ 1,896
Per Total kWh Purchased	$ 0.077	$ 0.080	$ 0.083	$ 0.080	$ 0.079	$ 0.081
Avg Monthly kWh Consumed per Customer	1,636	2,263	1,824	2,274	1,916	1,944
Avg Peak (kW) per Customer	3.08	4.19	3.52	4.27	3.62	3.71
OM&A Per Customer	$ 307.79	$ 222.78	$ 141.68	$ 219.38	$ 311.46	$ 203.97
Net Income Per Customer	$ 8.62	$ 19.70	$ 89.69	$ 63.73	$ 83.49	$ 61.57
Net Fixed Assets per Customer	$ 1,315	$ 1,066	$ 1,699	$ 1,139	$ 1,475	$ 1,330
Service Quality Requirements						
Low Voltage Connections (OEB Min. Standard: 90%)	100.00	100.00	93.10	100.00	97.60	98.60
High Voltage Connections (OEB Min. Standard: 90%)	N/A	N/A	100.00	100.00	100.00	N/A
Telephone Accessibility (OEB Min. Standard: 65%)	89.40	69.20	75.40	100.00	80.90	67.10
Appointments Met (OEB Min. Standard: 90%)	100.00	99.80	97.20	100.00	97.40	99.70
Written Response to Enquiries (OEB Min. Standard: 80%)	100.00	100.00	99.50	100.00	98.30	100.00
Emergency Urban Response (OEB Min. Standard: 80%)	100.00	100.00	90.50	100.00	100.00	98.00
Emergency Rural Response (OEB Min. Standard: 80%)	N/A	N/A	100.00	N/A	100.00	N/A
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	-	3.10	2.30	-	4.20	3.00
Appointments Scheduling (OEB Min. Standard: 90%)	100.00	99.20	96.20	100.00	97.90	95.50
Rescheduling a Missed Appointment: (OEB Standard: 100%)	N/A	100.00	91.40	N/A	100.00	100.00
Service Reliability Indices						
SAIDI-Annual	1.89	1.13	0.82	4.11	3.62	0.88
SAIFI-Annual	3.51	0.87	1.16	2.07	0.83	1.12
CAIDI-Annual	0.54	1.30	0.71	1.98	4.36	0.79
Loss of Supply Adjusted Service Reliability Indices						
SAIDI-Annual	1.63	1.08	0.79	2.95	3.27	0.85
SAIFI-Annual	1.51	0.76	1.10	1.55	0.66	1.00
CAIDI-Annual	1.07	1.42	0.72	1.91	4.96	0.84

N/A -No data reported for 2010.

Unitized Statistics and Service Quality Requirements For the year ended December 31, 2010	Middlesex Power Distribution Corporation	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket - Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.
# of Customers per sq km of Service Area	302.27	345.70	78.76	444.74	61.73	59.26
# of Customers per km of Line	62.87	46.40	31.07	30.73	26.18	23.05
Average Power & Distribution Revenue less Cost of Power & Related Costs						
Per Customer Annually	$ 419.76	$ 516.01	$ 430.04	$ 479.40	$ 537.48	$ 593.41
Per Total kWh Purchased	$ 0.015	$ 0.017	$ 0.017	$ 0.022	$ 0.022	$ 0.025
Average Cost of Power & Related Costs						
Per Customer Annually	$ 2,333	$ 2,629	$ 2,153	$ 1,809	$ 2,076	$ 1,841
Per Total kWh Purchased	$ 0.083	$ 0.085	$ 0.083	$ 0.083	$ 0.084	$ 0.078
Avg Monthly kWh Consumed per Customer	2,354	2,574	2,152	1,816	2,056	1,969
Avg Peak (kW) per Customer	4.45	5.03	4.16	3.60	3.96	3.92
OM&A Per Customer	$ 216.45	$ 267.26	$ 191.91	$ 202.84	$ 262.02	$ 224.50
Net Income Per Customer	$ 60.91	$ 116.37	$ 127.78	$ 63.00	$ 49.64	$ 93.27
Net Fixed Assets per Customer	$ 1,104	$ 1,573	$ 1,715	$ 1,550	$ 2,315	$ 2,515
Service Quality Requirements						
Low Voltage Connections (OEB Min. Standard: 90%)	100.00	94.10	99.10	95.90	84.70	100.00
High Voltage Connections (OEB Min. Standard: 90%)	N/A	N/A	100.00	100.00	85.70	100.00
Telephone Accessibility (OEB Min. Standard: 65%)	100.00	100.00	79.00	85.20	41.50	88.60
Appointments Met (OEB Min. Standard: 90%)	100.00	100.00	100.00	100.00	100.00	100.00
Written Response to Enquiries (OEB Min. Standard: 80%)	100.00	96.30	100.00	100.00	81.50	100.00
Emergency Urban Response (OEB Min. Standard: 80%)	100.00	100.00	100.00	100.00	100.00	100.00
Emergency Rural Response (OEB Min. Standard: 80%)	N/A	N/A	100.00	100.00	100.00	100.00
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	N/A	N/A	1.90	1.80	13.90	0.30
Appointments Scheduling (OEB Min. Standard: 90%)	100.00	100.00	N/A	86.80	100.00	100.00
Rescheduling a Missed Appointment: (OEB Standard: 100%)	N/A	N/A	N/A	N/A	100.00	N/A
Service Reliability Indices						
SAIDI-Annual	3.77	4.88	0.68	0.30	2.11	0.06
SAIFI-Annual	1.91	1.14	0.73	0.21	1.23	0.03
CAIDI-Annual	1.97	4.29	0.93	1.44	1.71	1.62
Loss of Supply Adjusted Service Reliability Indices						
SAIDI-Annual	0.11	4.88	0.55	0.30	1.77	0.06
SAIFI-Annual	0.07	1.14	0.40	0.21	1.06	0.03
CAIDI-Annual	1.62	4.29	1.38	1.44	1.67	1.62

N/A -No data reported for 2010.

Unitized Statistics and Service Quality Requirements For the year ended December 31, 2010	Norfolk Power Distribution Inc.	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation
# of Customers per sq km of Service Area	27.33	71.98	215.21	438.28	662.12	476.37
# of Customers per km of Line	24.66	38.88	16.29	43.55	63.95	41.09
Average Power & Distribution Revenue less Cost of Power & Related Costs						
Per Customer Annually	$ 585.34	$ 485.09	$ 445.84	$ 496.36	$ 441.86	$ 576.33
Per Total kWh Purchased	$ 0.029	$ 0.019	$ 0.021	$ 0.019	$ 0.019	$ 0.023
Average Cost of Power & Related Costs						
Per Customer Annually	$ 1,639	$ 1,864	$ 1,711	$ 2,080	$ 1,836	$ 1,943
Per Total kWh Purchased	$ 0.080	$ 0.075	$ 0.079	$ 0.082	$ 0.080	$ 0.078
Avg Monthly kWh Consumed per Customer	1,707	2,077	1,810	2,126	1,905	2,073
Avg Peak (kW) per Customer	3.54	3.85	3.49	4.33	3.69	3.94
OM&A Per Customer	$ 259.72	$ 205.27	$ 340.80	$ 175.79	$ 234.52	$ 325.24
Net Income Per Customer	$ 105.59	$ 89.17	$ 34.44	$ 74.13	$ 68.75	$ 43.83
Net Fixed Assets per Customer	$ 2,608	$ 1,584	$ 578	$ 1,998	$ 1,246	$ 1,197
Service Quality Requirements						
Low Voltage Connections (OEB Min. Standard: 90%)	93.40	100.00	100.00	95.00	100.00	100.00
High Voltage Connections (OEB Min. Standard: 90%)	N/A	100.00	100.00	N/A	N/A	N/A
Telephone Accessibility (OEB Min. Standard: 65%)	84.00	76.50	N/A	86.20	99.90	99.20
Appointments Met (OEB Min. Standard: 90%)	96.60	99.60	96.00	93.70	100.00	100.00
Written Response to Enquiries (OEB Min. Standard: 80%)	87.00	100.00	N/A	98.70	91.20	100.00
Emergency Urban Response (OEB Min. Standard: 80%)	89.70	100.00	N/A	N/A	100.00	100.00
Emergency Rural Response (OEB Min. Standard: 80%)	100.00	100.00	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	4.50	2.40	N/A	1.40	0.10	N/A
Appointments Scheduling (OEB Min. Standard: 90%)	91.50	100.00	100.00	100.00	93.70	100.00
Rescheduling a Missed Appointment: (OEB Standard: 100%)	N/A	N/A	N/A	100.00	100.00	N/A
Service Reliability Indices						
SAIDI-Annual	1.95	2.76	5.17	0.74	2.84	1.32
SAIFI-Annual	1.71	3.65	2.76	1.07	1.82	1.69
CAIDI-Annual	1.14	0.75	1.87	0.69	1.56	0.78
Loss of Supply Adjusted Service Reliability Indices						
SAIDI-Annual	1.48	2.72	4.62	0.73	1.00	0.24
SAIFI-Annual	1.43	3.55	2.03	1.15	0.88	0.86
CAIDI-Annual	1.03	0.77	2.28	0.64	1.14	0.28

N/A -No data reported for 2010.

Unitized Statistics and Service Quality Requirements For the year ended December 31, 2010	Oshawa PUC Networks Inc.	Ottawa River Power Corporation	Parry Sound Power Corporation	Peterborough Distribution Incorporated	Port Colborne Hydro Inc.	PowerStream Inc.
# of Customers per sq km of Service Area	353.76	299.29	225.13	555.75	74.54	403.90
# of Customers per km of Line	55.19	70.78	26.18	63.43	29.11	44.11
Average Power & Distribution Revenue less Cost of Power & Related Costs						
Per Customer Annually	$ 377.20	$ 351.77	$ 544.01	$ 435.00	$ 601.05	$ 501.23
Per Total kWh Purchased	$ 0.017	$ 0.019	$ 0.021	$ 0.018	$ 0.027	$ 0.019
Average Cost of Power & Related Costs						
Per Customer Annually	$ 1,513	$ 1,446	$ 2,149	$ 1,836	$ 1,771	$ 2,124
Per Total kWh Purchased	$ 0.069	$ 0.077	$ 0.083	$ 0.077	$ 0.080	$ 0.080
Avg Monthly kWh Consumed per Customer	1,816	1,565	2,161	1,995	1,843	2,214
Avg Peak (kW) per Customer	3.58	2.66	4.10	3.87	3.87	4.45
OM&A Per Customer	$ 167.61	$ 221.70	$ 359.27	$ 181.82	$ 380.38	$ 172.00
Net Income Per Customer	$ 58.89	$ 30.70	$ 29.27	$ 71.55	$ 15.93	$ 81.30
Net Fixed Assets per Customer	$ 988	$ 780	$ 1,140	$ 1,371	$ 1,319	$ 2,116
Service Quality Requirements						
Low Voltage Connections (OEB Min. Standard: 90%)	92.30	100.00	100.00	99.00	100.00	97.60
High Voltage Connections (OEB Min. Standard: 90%)	100.00	N/A	N/A	100.00	N/A	N/A
Telephone Accessibility (OEB Min. Standard: 65%)	59.20	99.80	100.00	73.00	87.30	68.30
Appointments Met (OEB Min. Standard: 90%)	99.10	100.00	98.50	95.00	100.00	99.30
Written Response to Enquiries (OEB Min. Standard: 80%)	100.00	100.00	100.00	99.70	100.00	99.10
Emergency Urban Response (OEB Min. Standard: 80%)	100.00	100.00	100.00	100.00	100.00	95.10
Emergency Rural Response (OEB Min. Standard: 80%)	N/A	N/A	N/A	N/A	100.00	N/A
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	4.30	-	-	1.70	1.90	4.90
Appointments Scheduling (OEB Min. Standard: 90%)	99.90	100.00	100.00	92.20	100.00	99.90
Rescheduling a Missed Appointment: (OEB Standard: 100%)	100.00	N/A	100.00	32.60	N/A	100.00
Service Reliability Indices						
SAIDI-Annual	0.65	1.21	0.07	2.22	1.69	0.81
SAIFI-Annual	0.80	1.40	0.03	1.59	1.74	0.92
CAIDI-Annual	0.81	0.86	2.00	1.39	0.97	0.88
Loss of Supply Adjusted Service Reliability Indices						
SAIDI-Annual	0.62	0.71	0.07	2.11	1.69	0.54
SAIFI-Annual	0.61	0.79	0.03	1.51	1.74	0.80
CAIDI-Annual	1.02	0.89	2.00	1.40	0.97	0.67

N/A -No data reported for 2010.

Unitized Statistics and Service Quality Requirements For the year ended December 31, 2010	PUC Distribution Inc.	Renfrew Hydro Inc.	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.
# of Customers per sq km of Service Area	96.11	319.62	323.22	5.14	497.55	129.94
# of Customers per km of Line	44.84	75.55	61.89	13.05	66.47	42.03
Average Power & Distribution Revenue less Cost of Power & Related Costs						
Per Customer Annually	$ 463.03	$ 391.83	$ 375.56	$ 668.19	$ 394.89	$ 358.98
Per Total kWh Purchased	$ 0.021	$ 0.016	$ 0.019	$ 0.025	$ 0.021	$ 0.018
Average Cost of Power & Related Costs						
Per Customer Annually	$ 1,621	$ 2,022	$ 1,569	$ 1,889	$ 1,518	$ 1,585
Per Total kWh Purchased	$ 0.075	$ 0.084	$ 0.078	$ 0.070	$ 0.081	$ 0.080
Avg Monthly kWh Consumed per Customer	1,804	2,009	1,670	2,261	1,556	1,652
Avg Peak (kW) per Customer	3.31	3.96	3.78	4.55	3.09	3.03
OM&A Per Customer	$ 264.30	$ 250.57	$ 282.71	$ 426.09	$ 203.23	$ 248.69
Net Income Per Customer	$ 53.69	$ 9.24	$ 34.67	$ 107.81	$ 32.61	$ 9.54
Net Fixed Assets per Customer	$ 1,287	$ 1,086	$ 709	$ 1,644	$ 1,142	$ 1,284
Service Quality Requirements						
Low Voltage Connections (OEB Min. Standard: 90%)	96.70	100.00	100.00	100.00	98.80	98.30
High Voltage Connections (OEB Min. Standard: 90%)	100.00	N/A	N/A	N/A	N/A	100.00
Telephone Accessibility (OEB Min. Standard: 65%)	70.10	85.50	97.00	97.60	89.50	92.70
Appointments Met (OEB Min. Standard: 90%)	92.40	100.00	100.00	98.80	99.70	99.10
Written Response to Enquiries (OEB Min. Standard: 80%)	99.30	100.00	100.00	100.00	98.40	97.80
Emergency Urban Response (OEB Min. Standard: 80%)	92.10	100.00	100.00	100.00	100.00	96.70
Emergency Rural Response (OEB Min. Standard: 80%)	N/A	N/A	N/A	100.00	N/A	93.90
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	5.00	6.70	N/A	0.70	2.10	0.70
Appointments Scheduling (OEB Min. Standard: 90%)	97.30	100.00	100.00	99.00	97.20	99.10
Rescheduling a Missed Appointment: (OEB Standard: 100%)	72.70	N/A	N/A	100.00	50.00	100.00
Service Reliability Indices						
SAIDI-Annual	2.11	2.50	0.91	10.99	0.34	2.94
SAIFI-Annual	2.83	2.22	1.75	3.57	0.57	4.56
CAIDI-Annual	0.75	1.12	0.52	3.08	0.60	0.64
Loss of Supply Adjusted Service Reliability Indices						
SAIDI-Annual	2.11	2.50	0.08	0.90	0.34	2.60
SAIFI-Annual	2.83	2.22	0.03	0.56	0.57	3.68
CAIDI-Annual	0.75	1.12	2.47	1.60	0.60	0.71

N/A -No data reported for 2010.

Unitized Statistics and Service Quality Requirements For the year ended December 31, 2010	Tillsonburg Hydro Inc.	Toronto Hydro-Electric System Limited	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.
# of Customers per sq km of Service Area	279.17	1111.72	176.16	197.48	77.25	248.97
# of Customers per km of Line	42.95	70.11	48.92	50.19	33.56	48.55
Average Power & Distribution Revenue less Cost of Power & Related Costs						
Per Customer Annually	$ 496.53	$ 752.26	$ 434.20	$ 330.45	$ 500.62	$ 421.27
Per Total kWh Purchased	$ 0.017	$ 0.021	$ 0.018	$ 0.032	$ 0.018	$ 0.020
Average Cost of Power & Related Costs						
Per Customer Annually	$ 2,298	$ 2,554	$ 1,854	$ 847	$ 2,230	$ 1,677
Per Total kWh Purchased	$ 0.081	$ 0.070	$ 0.079	$ 0.081	$ 0.078	$ 0.081
Avg Monthly kWh Consumed per Customer	2,378	3,050	1,968	867	2,375	1,727
Avg Peak (kW) per Customer	5.33	5.77	3.73	1.77	4.58	3.71
OM&A Per Customer	$ 330.22	$ 300.32	$ 182.51	$ 180.81	$ 190.70	$ 221.07
Net Income Per Customer	$ 67.57	$ 92.60	$ 71.42	$ 65.02	$ 103.65	$ 45.88
Net Fixed Assets per Customer	$ 885	$ 3,066	$ 1,484	$ 732	$ 2,461	$ 1,018
Service Quality Requirements						
Low Voltage Connections (OEB Min. Standard: 90%)	100.00	96.20	100.00	100.00	100.00	100.00
High Voltage Connections (OEB Min. Standard: 90%)	N/A	97.50	100.00	N/A	100.00	N/A
Telephone Accessibility (OEB Min. Standard: 65%)	97.90	69.90	83.90	100.00	88.70	99.90
Appointments Met (OEB Min. Standard: 90%)	100.00	99.90	98.20	100.00	96.90	99.90
Written Response to Enquiries (OEB Min. Standard: 80%)	N/A	97.50	99.90	100.00	100.00	100.00
Emergency Urban Response (OEB Min. Standard: 80%)	100.00	83.00	98.70	98.10	89.50	100.00
Emergency Rural Response (OEB Min. Standard: 80%)	N/A	N/A	100.00	100.00	100.00	N/A
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	1.00	2.50	2.20	N/A	3.40	1.50
Appointments Scheduling (OEB Min. Standard: 90%)	100.00	95.60	96.00	100.00	100.00	99.90
Rescheduling a Missed Appointment: (OEB Standard: 100%)	N/A	100.00	100.00	N/A	100.00	100.00
Service Reliability Indices						
SAIDI-Annual	4.10	1.66	0.92	1.90	0.79	0.85
SAIFI-Annual	6.93	1.95	1.58	1.52	0.91	1.66
CAIDI-Annual	0.59	0.85	0.58	1.24	0.87	0.51
Loss of Supply Adjusted Service Reliability Indices						
SAIDI-Annual	1.17	1.19	0.77	0.89	0.76	0.77
SAIFI-Annual	0.78	1.54	1.14	0.50	0.85	0.96
CAIDI-Annual	1.49	0.77	0.67	1.77	0.89	0.81

N/A -No data reported for 2010.

Unitized Statistics and Service Quality Requirements For the year ended December 31, 2010	Wellington North Power Inc.	West Coast Huron Energy Inc.	West Perth Power Inc.	Westario Power Inc.	Whitby Hydro Electric Corporation	Woodstock Hydro Services Inc.
# of Customers per sq km of Service Area	258.07	471.25	341.50	449.12	268.03	519.79
# of Customers per km of Line	47.54	58.00	56.92	42.73	37.74	60.78
Average Power & Distribution Revenue less Cost of Power & Related Costs						
Per Customer Annually	$ 518.96	$ 599.68	$ 428.18	$ 414.89	$ 479.83	$ 446.43
Per Total kWh Purchased	$ 0.018	$ 0.016	$ 0.014	$ 0.019	$ 0.021	$ 0.017
Average Cost of Power & Related Costs						
Per Customer Annually	$ 2,246	$ 1,924	$ 2,432	$ 1,664	$ 1,531	$ 1,599
Per Total kWh Purchased	$ 0.079	$ 0.051	$ 0.079	$ 0.078	$ 0.067	$ 0.062
Avg Monthly kWh Consumed per Customer	2,367	3,165	2,552	1,781	1,899	2,156
Avg Peak (kW) per Customer	4.47	6.32	4.86	3.33	3.84	4.07
OM&A Per Customer	$ 348.98	$ 351.48	$ 473.30	$ 195.13	$ 223.49	$ 234.68
Net Income Per Customer	$ 55.80	$ 143.78	$ (143.26)	$ 82.62	$ 63.23	$ 16.22
Net Fixed Assets per Customer	$ 1,326	$ 1,097	$ 967	$ 1,373	$ 1,585	$ 1,397
Service Quality Requirements						
Low Voltage Connections (OEB Min. Standard: 90%)	100.00	100.00	100.00	96.90	100.00	99.60
High Voltage Connections (OEB Min. Standard: 90%)	N/A	100.00	N/A	100.00	N/A	100.00
Telephone Accessibility (OEB Min. Standard: 65%)	100.00	99.10	98.00	81.00	95.50	75.30
Appointments Met (OEB Min. Standard: 90%)	99.80	100.00	91.70	97.20	100.00	98.20
Written Response to Enquiries (OEB Min. Standard: 80%)	100.00	100.00	100.00	94.60	100.00	100.00
Emergency Urban Response (OEB Min. Standard: 80%)	100.00	N/A	100.00	100.00	100.00	100.00
Emergency Rural Response (OEB Min. Standard: 80%)	N/A	N/A	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	-	0.40	4.50	10.00	5.00	3.80
Appointments Scheduling (OEB Min. Standard: 90%)	99.60	100.00	100.00	98.30	97.50	92.60
Rescheduling a Missed Appointment: (OEB Standard: 100%)	N/A	N/A	N/A	100.00	N/A	100.00
Service Reliability Indices						
SAIDI-Annual	0.00	0.05	1.11	1.54	0.49	0.30
SAIFI-Annual	2.22	0.56	0.64	9.51	0.62	0.69
CAIDI-Annual	0.00	0.09	1.75	0.16	0.79	0.43
Loss of Supply Adjusted Service Reliability Indices						
SAIDI-Annual	0.00	0.05	1.11	1.15	0.48	0.30
SAIFI-Annual	0.04	0.56	0.64	9.19	0.54	0.69
CAIDI-Annual	0.03	0.09	1.75	0.12	0.88	0.43

N/A -No data reported for 2010.

Statistics by Customer Class For the year ended December 31, 2010	Algoma Power Inc.	Atikokan Hydro Inc.	Bluewater Power Distribution Corporation	Brant County Power Inc.	Brantford Power Inc.	Burlington Hydro Inc.
Residential Customers						
Number of Customers	10,623	1,409	31,750	8,215	34,495	58,263
Billed kWh	83,582,747	10,673,947	262,967,731	86,183,557	289,840,430	579,116,811
Distribution Revenue	$ 6,917,195	$ 688,109	$ 10,031,282	$ 2,922,122	$ 8,635,913	$ 17,690,931
Billed kWh per Customer	7,868	7,576	8,282	10,491	8,402	9,940
Distribution Revenue per Customer	$ 651	$ 488	$ 316	$ 356	$ 250	$ 304
General Service <50kW Customers						
Number of Customers	946	232	3,511	1,337	2,735	5,045
Billed kWh	26,062,992	5,391,247	109,481,922	38,493,240	99,142,979	178,122,314
Distribution Revenue	$ 857,022	$ 256,727	$ 2,972,249	$ 944,402	$ 1,419,084	$ 3,837,876
Billed kWh per Customer	27,551	23,238	31,183	28,791	36,250	35,307
Distribution Revenue per Customer	$ 906	$ 1,107	$ 847	$ 706	$ 519	$ 761
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	35	22	424	115	424	1,021
Number of Large Users	8	0	3	0	0	0
Number of Sub Transmission Customers	0	0	0	0	0	0
Billed kWh	70,938,155	5,466,469	658,368,304	163,622,296	522,228,963	943,596,172
Distribution Revenue	$ 661,531	$ 127,111	$ 4,822,049	$ 1,714,406	$ 4,962,439	$ 6,872,498
Billed kWh per Customer	1,649,725	248,476	1,541,846	1,422,803	1,231,672	924,188
Distribution Revenue per Customer	$ 15,384	$ 5,778	$ 11,293	$ 14,908	$ 11,704	$ 6,731
Unmetered Scattered Load Connections						
Number of Connections	0	8	257	50	446	25
Billed kWh	0	2,714	2,198,681	489,924	1,571,067	3,658,058
Distribution Revenue	$ -	$ 9,932	$ 120,612	$ 10,731	$ 81,632	$ 132,261
Billed kWh per Connection	-	339	8,555	9,798	3,523	146,322
Distribution Revenue per Connection	-	$ 1,241	$ 469	$ 215	$ 183	$ 5,290

Statistics by Customer Class For the year ended December 31, 2010	Cambridge and North Dumfries Hydro Inc.	Canadian Niagara Power Inc.	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	Chatham-Kent Hydro Inc.	Clinton Power Corporation
Residential Customers						
Number of Customers	45,526	14,278	5,692	1,132	28,512	1,403
Billed kWh	395,342,413	114,051,203	45,162,580	13,585,926	236,272,579	11,595,218
Distribution Revenue	$ 11,194,272	$ 4,750,819	$ 1,542,945	$ 391,291	$ 7,941,291	$ 267,176
Billed kWh per Customer	8,684	7,988	7,934	12,002	8,287	8,265
Distribution Revenue per Customer	$ 246	$ 333	$ 271	$ 346	$ 279	$ 190
General Service <50kW Customers						
Number of Customers	4,627	1,232	709	160	3,118	217
Billed kWh	163,489,557	34,886,295	20,301,193	4,875,282	95,572,850	5,392,837
Distribution Revenue	$ 2,802,662	$ 1,131,797	$ 458,819	$ 118,670	$ 2,246,737	$ 95,784
Billed kWh per Customer	35,334	28,317	28,634	30,471	30,652	24,852
Distribution Revenue per Customer	$ 606	$ 919	$ 647	$ 742	$ 721	$ 441
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	735	125	62	14	402	19
Number of Large Users	2	0	0	0	1	0
Number of Sub Transmission Customers	0	0	0	0	0	0
Billed kWh	898,848,225	129,724,134	81,977,657	7,374,502	381,018,040	12,341,720
Distribution Revenue	$ 8,044,185	$ 2,661,050	$ 616,357	$ 73,439	$ 3,667,069	$ 139,029
Billed kWh per Customer	1,219,604	1,037,793	1,322,220	526,750	945,454	649,564
Distribution Revenue per Customer	$ 10,915	$ 21,288	$ 9,941	$ 5,246	$ 9,099	$ 7,317
Unmetered Scattered Load Connections						
Number of Connections	63	19	6	6	192	13
Billed kWh	2,126,378	668,731	438,125	7,391	870,035	56,040
Distribution Revenue	$ 74,239	$ 51,965	$ 11,470	$ 1,599	$ 16,544	$ 1,783
Billed kWh per Connection	33,752	35,196	73,021	1,232	4,531	4,311
Distribution Revenue per Connection	$ 1,178	$ 2,735	$ 1,912	$ 267	$ 86	$ 137

Statistics by Customer Class For the year ended December 31, 2010	COLLUS Power Corporation	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	Eastern Ontario Power Inc.	Enersource Hydro Mississauga Inc.	EnWin Utilities Ltd.
Residential Customers						
Number of Customers	13,727	1,777	9,899	3,100	171,247	76,720
Billed kWh	125,224,900	19,868,483	93,358,872	28,625,240	1,586,325,915	647,461,708
Distribution Revenue	$ 3,650,694	$ 505,323	$ 783,500	$ 1,085,000	$ 47,758,866	$ 22,978,356
Billed kWh per Customer	9,123	11,181	9,431	9,234	9,263	8,439
Distribution Revenue per Customer	$ 266	$ 284	$ 79	$ 350	$ 279	$ 300
General Service <50kW Customers						
Number of Customers	1,687	170	1,187	438	17,197	6,955
Billed kWh	49,527,086	4,729,493	27,544,928	12,306,415	661,646,252	223,701,633
Distribution Revenue	$ 891,621	$ 108,823	$ 58,725	$ 389,101	$ 16,064,175	$ 5,713,015
Billed kWh per Customer	29,358	27,821	23,205	28,097	38,475	32,164
Distribution Revenue per Customer	$ 529	$ 640	$ 49	$ 888	$ 934	$ 821
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	119	11	119	23	4,506	1,181
Number of Large Users	0	0	0	0	10	10
Number of Sub Transmission Customers	0	0	0	0	0	0
Billed kWh	161,887,742	4,088,585	113,774,116	17,583,459	5,410,120,921	1,439,651,148
Distribution Revenue	$ 749,815	$ 77,503	$ 482,836	$ 396,591	$ 53,725,866	$ 17,845,299
Billed kWh per Customer	1,360,401	371,690	956,085	764,498	1,197,990	1,208,775
Distribution Revenue per Customer	$ 6,301	$ 7,046	$ 4,057	$ 17,243	$ 11,897	$ 14,983
Unmetered Scattered Load Connections						
Number of Connections	32	19	0	6	2,934	787
Billed kWh	497,288	89,786	0	160,435	10,986,351	3,697,869
Distribution Revenue	$ 7,991	$ 7,643	$ -	$ 14,599	$ 624,305	$ 93,408
Billed kWh per Connection	15,540	4,726	-	26,739	3,744	4,699
Distribution Revenue per Connection	$ 250	$ 402	-	$ 2,433	$ 213	$ 119

Statistics by Customer Class For the year ended December 31, 2010	Erie Thames Powerlines Corporation	Espanola Regional Hydro Distribution Corporation	Essex Powerlines Corporation	Festival Hydro Inc.	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.
Residential Customers						
Number of Customers	12,847	2,850	25,915	17,373	3,307	42,068
Billed kWh	115,184,785	31,226,253	280,065,614	141,316,645	38,880,708	394,465,898
Distribution Revenue	$ 3,022,957	$ 742,990	$ 7,561,421	$ 5,325,821	$ 828,911	$ 24,607,241
Billed kWh per Customer	8,966	10,957	10,807	8,134	11,757	9,377
Distribution Revenue per Customer	$ 235	$ 261	$ 292	$ 307	$ 251	$ 585
General Service <50kW Customers						
Number of Customers	1,378	425	2,046	1,985	419	4,118
Billed kWh	35,509,255	11,572,990	72,544,120	65,179,456	14,833,271	144,489,006
Distribution Revenue	$ 679,956	$ 262,308	$ 858,010	$ 1,633,969	$ 238,421	$ 26,676,335
Billed kWh per Customer	25,769	27,231	35,457	32,836	35,402	35,087
Distribution Revenue per Customer	$ 493	$ 617	$ 419	$ 823	$ 569	$ 6,478
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	146	25	222	220	51	524
Number of Large Users	2	0	0	1	0	0
Number of Sub Transmission Customers	0	0	0	0	0	0
Billed kWh	245,543,151	17,160,375	234,841,610	360,896,551	26,245,189	382,334,753
Distribution Revenue	$ 2,194,496	$ 174,049	$ 2,051,654	$ 2,333,201	$ 381,776	$ 4,504,045
Billed kWh per Customer	1,659,075	686,415	1,057,845	1,633,016	514,612	729,646
Distribution Revenue per Customer	$ 14,828	$ 6,962	$ 9,242	$ 10,557	$ 7,486	$ 8,596
Unmetered Scattered Load Connections						
Number of Connections	105	21	150	224	6	200
Billed kWh	511,304	170,043	1,709,104	673,251	67,445	2,285,597
Distribution Revenue	$ 12,146	$ 2,455	$ 61,055	$ 34,739	$ 618	$ -
Billed kWh per Connection	4,870	8,097	11,394	3,006	11,241	11,428
Distribution Revenue per Connection	$ 116	$ 117	$ 407	$ 155	$ 103	$ -

Statistics by Customer Class For the year ended December 31, 2010	Grimsby Power Incorporated	Guelph Hydro Electric Systems Inc.	Haldimand County Hydro Inc.	Halton Hills Hydro Inc.	Hearst Power Distribution Company Limited	Horizon Utilities Corporation
Residential Customers						
Number of Customers	9,379	46,001	18,465	18,944	2,292	214,133
Billed kWh	96,445,307	364,874,674	172,161,499	224,697,945	25,225,707	1,684,535,439
Distribution Revenue	$ 2,473,623	$ 13,197,037	$ 8,514,378	$ 5,445,033	$ 449,199	$ 56,999,672
Billed kWh per Customer	10,283	7,932	9,324	11,861	11,006	7,867
Distribution Revenue per Customer	$ 264	$ 287	$ 461	$ 287	$ 196	$ 266
General Service <50kW Customers						
Number of Customers	662	3,647	2,369	1,655	401	18,053
Billed kWh	19,722,899	145,047,954	57,658,761	57,461,968	11,529,904	581,299,813
Distribution Revenue	$ 395,713	$ 2,947,049	$ 1,922,423	$ 1,033,672	$ 129,389	$ 9,814,954
Billed kWh per Customer	29,793	39,772	24,339	34,720	28,753	32,200
Distribution Revenue per Customer	$ 598	$ 808	$ 811	$ 625	$ 323	$ 544
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	110	598	137	191	41	2,265
Number of Large Users	0	4	0	0	0	13
Number of Sub Transmission Customers	0	0	0	0	0	0
Billed kWh	70,390,802	1,104,522,620	115,484,343	228,049,777	36,063,444	2,552,967,787
Distribution Revenue	$ 458,002	$ 7,526,753	$ 1,808,034	$ 2,299,937	$ 186,871	$ 15,887,710
Billed kWh per Customer	639,916	1,834,755	842,951	1,193,978	879,596	1,120,706
Distribution Revenue per Customer	$ 4,164	$ 12,503	$ 13,197	$ 12,042	$ 4,558	$ 6,974
Unmetered Scattered Load Connections						
Number of Connections	80	578	78	139	0	3,174
Billed kWh	401,097	2,426,370	454,181	914,221	0	12,474,726
Distribution Revenue	$ 16,356	$ 12,926	$ 19,637	$ 30,188	$ -	$ 592,592
Billed kWh per Connection	5,014	4,198	5,823	6,577	-	3,930
Distribution Revenue per Connection	$ 204	$ 22	$ 252	$ 217	-	$ 187

Statistics by Customer Class For the year ended December 31, 2010	Hydro 2000 Inc.	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.	Hydro Ottawa Limited	Innisfil Hydro Distribution Systems Limited
Residential Customers						
Number of Customers	1,041	4,817	124,592	1,093,342	273,758	13,747
Billed kWh	14,930,159	52,798,659	1,161,471,420	11,964,000,000	2,272,176,243	159,406,547
Distribution Revenue	$ 195,168	$ 419,638	$ 33,914,841	$ 690,123,000	$ 81,462,521	$ 5,860,852
Billed kWh per Customer	14,342	10,961	9,322	10,943	8,300	11,596
Distribution Revenue per Customer	$ 187	$ 87	$ 272	$ 631	$ 298	$ 426
General Service <50kW Customers						
Number of Customers	143	593	7,975	101,638	23,548	892
Billed kWh	4,768,074	20,553,207	295,707,937	3,956,000,000	726,404,260	31,366,364
Distribution Revenue	$ 77,777	$ 104,192	$ 7,213,933	$ 130,653,000	$ 18,530,472	$ 602,655
Billed kWh per Customer	33,343	34,660	37,079	38,922	30,848	35,164
Distribution Revenue per Customer	$ 544	$ 176	$ 905	$ 1,285	$ 787	$ 676
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	12	86	1,655	7,628	3,346	68
Number of Large Users	0	0	6	0	12	0
Number of Sub Transmission Customers	0	0	0	422	0	0
Billed kWh	4,593,159	84,920,330	2,291,565,397	5,743,000,000	4,532,399,117	54,942,977
Distribution Revenue	$ 26,265	$ 253,919	$ 18,668,003	$ 144,626,000	$ 44,737,727	$ 754,395
Billed kWh per Customer	382,763	987,446	1,379,630	713,416	1,349,732	807,985
Distribution Revenue per Customer	$ 2,189	$ 2,953	$ 11,239	$ 17,966	$ 13,323	$ 11,094
Unmetered Scattered Load Connections						
Number of Connections	6	5	0	0	3,084	82
Billed kWh	19,706	254,840	0	0	17,309,021	530,509
Distribution Revenue	$ 1,024	$ 709	$ -	$ -	$ -	$ 41,669
Billed kWh per Connection	3,284	50,968	-	-	5,613	6,470
Distribution Revenue per Connection	$ 171	$ 142	-	-	$ -	$ 508

Statistics by Customer Class For the year ended December 31, 2010	Kenora Hydro Electric Corporation Ltd.	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	London Hydro Inc.
Residential Customers						
Number of Customers	4,770	23,336	78,142	8,369	7,782	133,452
Billed kWh	40,203,282	189,807,088	671,668,025	75,492,423	77,894,336	1,146,514,255
Distribution Revenue	$ 1,172,155	$ 5,264,251	$ 19,029,203	$ 1,794,942	$ 2,500,355	$ 38,555,489
Billed kWh per Customer	8,428	8,134	8,595	9,020	10,010	8,591
Distribution Revenue per Customer	$ 246	$ 226	$ 244	$ 214	$ 321	$ 289
General Service <50kW Customers						
Number of Customers	741	3,264	7,493	1,069	1,556	11,897
Billed kWh	24,326,248	92,291,447	243,721,827	35,983,197	41,668,843	407,620,994
Distribution Revenue	$ 321,003	$ 1,822,258	$ 4,843,966	$ 558,525	$ 1,026,896	$ 7,936,510
Billed kWh per Customer	32,829	28,276	32,527	33,661	26,779	34,263
Distribution Revenue per Customer	$ 433	$ 558	$ 646	$ 522	$ 660	$ 667
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	69	341	975	133	101	1,621
Number of Large Users	0	3	1	0	0	4
Number of Sub Transmission Customers	0	0	0	0	0	0
Billed kWh	44,296,705	422,382,562	952,018,606	146,793,054	82,034,432	1,792,696,694
Distribution Revenue	$ 430,642	$ 2,291,480	$ 11,039,292	$ 1,227,056	$ 827,995	$ 11,258,842
Billed kWh per Customer	641,981	1,227,856	975,429	1,103,707	812,222	1,103,198
Distribution Revenue per Customer	$ 6,241	$ 6,661	$ 11,311	$ 9,226	$ 8,198	$ 6,929
Unmetered Scattered Load Connections						
Number of Connections	33	158	811	77	41	1,494
Billed kWh	173,482	2,258,139	3,374,629	757,530	141,050	5,523,748
Distribution Revenue	$ 5,358	$ 45,845	$ 150,973	$ 31,046	$ 10,150	$ 76,736
Billed kWh per Connection	5,257	14,292	4,161	9,838	3,440	3,697
Distribution Revenue per Connection	$ 162	$ 290	$ 186	$ 403	$ 248	$ 51

Statistics by Customer Class For the year ended December 31, 2010	Middlesex Power Distribution Corporation	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newmarket - Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.
Residential Customers						
Number of Customers	6,984	6,063	26,587	29,533	45,840	6,537
Billed kWh	64,995,244	47,915,407	258,659,735	277,978,370	451,343,387	67,066,095
Distribution Revenue	$ 2,207,239	$ 1,818,869	$ 7,569,337	$ 9,543,384	$ 13,704,970	$ 2,257,949
Billed kWh per Customer	9,306	7,903	9,729	9,412	9,846	10,259
Distribution Revenue per Customer	$ 316	$ 300	$ 285	$ 323	$ 299	$ 345
General Service <50kW Customers						
Number of Customers	779	738	2,283	2,973	4,357	1,224
Billed kWh	22,008,816	24,725,350	79,867,181	93,701,712	121,294,614	33,559,042
Distribution Revenue	$ 315,841	$ 521,305	$ 1,655,769	$ 2,560,097	$ 3,350,656	$ 1,121,003
Billed kWh per Customer	28,253	33,503	34,983	31,518	27,839	27,418
Distribution Revenue per Customer	$ 405	$ 706	$ 725	$ 861	$ 769	$ 916
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	95	113	270	405	851	121
Number of Large Users	1	0	2	0	0	0
Number of Sub Transmission Customers	0	0	0	0	0	0
Billed kWh	122,492,084	132,869,301	379,584,041	309,550,101	611,065,862	76,691,746
Distribution Revenue	$ 376,267	$ 901,183	$ 2,465,639	$ 3,515,008	$ 8,597,223	$ 988,523
Billed kWh per Customer	1,275,959	1,175,835	1,395,530	764,321	718,056	633,816
Distribution Revenue per Customer	$ 3,919	$ 7,975	$ 9,065	$ 8,679	$ 10,102	$ 8,170
Unmetered Scattered Load Connections						
Number of Connections	53	12	184	115	465	20
Billed kWh	321,271	461,535	1,281,024	374,072	2,345,772	209,503
Distribution Revenue	$ 7,262	$ 16,017	$ 36,889	$ 26,602	$ 128,953	$ 16,202
Billed kWh per Connection	6,062	38,461	6,962	3,253	5,045	10,475
Distribution Revenue per Connection	$ 137	$ 1,335	$ 200	$ 231	$ 277	$ 810

Statistics by Customer Class For the year ended December 31, 2010	Norfolk Power Distribution Inc.	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation
Residential Customers						
Number of Customers	16,769	20,845	5,202	56,902	9,963	11,357
Billed kWh	141,859,487	206,535,118	41,793,455	625,890,073	86,211,880	107,193,730
Distribution Revenue	$ 6,921,061	$ 6,041,374	$ 1,654,167	$ 17,594,797	$ 3,120,339	$ 3,455,067
Billed kWh per Customer	8,460	9,908	8,034	10,999	8,653	9,439
Distribution Revenue per Customer	$ 413	$ 290	$ 318	$ 309	$ 313	$ 304
General Service <50kW Customers						
Number of Customers	2,009	2,636	755	4,886	1,163	1,344
Billed kWh	60,492,342	85,042,099	19,817,364	178,458,347	36,096,661	47,478,083
Distribution Revenue	$ 2,042,648	$ 2,053,756	$ 467,367	$ 4,083,476	$ 764,402	$ 1,269,092
Billed kWh per Customer	30,111	32,262	26,248	36,524	31,038	35,326
Distribution Revenue per Customer	$ 1,017	$ 779	$ 619	$ 836	$ 657	$ 944
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	162	273	69	886	130	161
Number of Large Users	0	0	0	0	0	0
Number of Sub Transmission Customers	0	0	0	0	0	0
Billed kWh	162,124,748	271,065,841	60,032,163	788,869,762	123,390,551	150,666,402
Distribution Revenue	$ 1,687,648	$ 2,347,615	$ 277,280	$ 7,486,519	$ 763,897	$ 1,844,090
Billed kWh per Customer	1,000,770	992,915	870,031	890,372	949,158	935,816
Distribution Revenue per Customer	$ 10,418	$ 8,599	$ 4,019	$ 8,450	$ 5,876	$ 11,454
Unmetered Scattered Load Connections						
Number of Connections	46	20	19	663	158	153
Billed kWh	495,360	165,123	128,847	4,008,590	373,728	824,780
Distribution Revenue	$ 139	$ 5,145	$ 4,479	$ 146,426	$ 14,356	$ 31,200
Billed kWh per Connection	10,769	8,256	6,781	6,046	2,365	5,391
Distribution Revenue per Connection	$ 3	$ 257	$ 236	$ 221	$ 91	$ 204

Statistics by Customer Class For the year ended December 31, 2010	Oshawa PUC Networks Inc.	Ottawa River Power Corporation	Parry Sound Power Corporation	Peterborough Distribution Incorporated	Port Colborne Hydro Inc.	PowerStream Inc.
Residential Customers						
Number of Customers	48,387	8,955	2,773	31,037	8,151	290,951
Billed kWh	500,205,636	76,783,544	32,389,316	284,955,081	64,264,350	2,727,096,928
Distribution Revenue	$ 11,202,438	$ 2,028,282	$ 965,985	$ 7,842,079	$ 2,947,445	$ 79,661,790
Billed kWh per Customer	10,338	8,574	11,680	9,181	7,884	9,373
Distribution Revenue per Customer	$ 232	$ 226	$ 348	$ 253	$ 362	$ 274
General Service <50kW Customers						
Number of Customers	3,795	1,372	538	3,588	937	30,076
Billed kWh	137,665,867	33,379,737	15,833,269	115,582,263	22,781,401	1,034,252,535
Distribution Revenue	$ 2,784,240	$ 616,261	$ 330,304	$ 2,306,025	$ 649,197	$ 22,110,870
Billed kWh per Customer	36,276	24,329	29,430	32,214	24,313	34,388
Distribution Revenue per Customer	$ 734	$ 449	$ 614	$ 643	$ 693	$ 735
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	527	148	66	385	81	4,512
Number of Large Users	1	0	0	2	0	1
Number of Sub Transmission Customers	0	0	0	0	0	0
Billed kWh	490,937,909	75,272,399	35,710,193	392,431,436	102,093,247	4,502,194,401
Distribution Revenue	$ 4,284,913	$ 817,672	$ 447,494	$ 3,156,654	$ 1,456,384	$ 43,477,190
Billed kWh per Customer	929,807	508,597	541,064	1,014,035	1,260,410	997,606
Distribution Revenue per Customer	$ 8,115	$ 5,525	$ 6,780	$ 8,157	$ 17,980	$ 9,634
Unmetered Scattered Load Connections						
Number of Connections	309	72	19	384	14	2,868
Billed kWh	2,969,396	465,819	56,466	1,667,651	695,082	12,399,878
Distribution Revenue	$ 57,664	$ 4,113	$ 5,297	$ 245,285	$ 40,110	$ 596,910
Billed kWh per Connection	9,610	6,470	2,972	4,343	49,649	4,324
Distribution Revenue per Connection	$ 187	$ 57	$ 279	$ 639	$ 2,865	$ 208

Statistics by Customer Class For the year ended December 31, 2010	PUC Distribution Inc.	Renfrew Hydro Inc.	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.
Residential Customers						
Number of Customers	29,086	3,654	4,982	2,312	14,538	44,559
Billed kWh	326,493,714	30,305,144	44,191,614	31,178,902	120,949,829	335,657,888
Distribution Revenue	$ 7,880,033	$ 896,369	$ 1,147,032	$ 987,511	$ 3,820,683	$ 9,933,606
Billed kWh per Customer	11,225	8,294	8,870	13,486	8,320	7,533
Distribution Revenue per Customer	$ 271	$ 245	$ 230	$ 427	$ 263	$ 223
General Service <50kW Customers						
Number of Customers	3,349	442	770	394	1,687	4,415
Billed kWh	91,377,364	12,427,065	20,418,777	14,190,567	36,670,176	132,889,381
Distribution Revenue	$ 2,211,172	$ 229,899	$ 378,223	$ 319,719	$ 837,051	$ 2,633,057
Billed kWh per Customer	27,285	28,116	26,518	36,017	21,737	30,100
Distribution Revenue per Customer	$ 660	$ 520	$ 491	$ 811	$ 496	$ 596
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	435	59	66	48	194	534
Number of Large Users	0	0	0	0	0	0
Number of Sub Transmission Customers	0	0	0	0	0	0
Billed kWh	257,036,820	51,703,213	41,354,016	25,204,983	137,249,474	462,862,459
Distribution Revenue	$ 3,604,998	$ 286,466	$ 346,031	$ 322,349	$ 1,114,532	$ 3,451,872
Billed kWh per Customer	590,889	876,326	626,576	525,104	707,472	866,784
Distribution Revenue per Customer	$ 8,287	$ 4,855	$ 5,243	$ 6,716	$ 5,745	$ 6,464
Unmetered Scattered Load Connections						
Number of Connections	16	34	48	9	2	471
Billed kWh	837,229	150,176	337,164	35,962	9,094	1,952,259
Distribution Revenue	$ 23,212	$ 6,380	$ 15,968	$ 3,305	$ 609	$ 98,936
Billed kWh per Connection	52,327	4,417	7,024	3,996	4,547	4,145
Distribution Revenue per Connection	$ 1,451	$ 188	$ 333	$ 367	$ 304	$ 210

Statistics by Customer Class For the year ended December 31, 2010	Tillsonburg Hydro Inc.	Toronto Hydro-Electric System Limited	Veridian Connections Inc.	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.
Residential Customers						
Number of Customers	5,954	620,501	102,929	11,238	45,863	19,543
Billed kWh	53,434,213	5,209,204,594	972,134,187	77,874,801	413,251,129	159,733,338
Distribution Revenue	$ 1,766,057	$ 211,702,780	$ 29,469,856	$ 2,784,335	$ 13,612,900	$ 5,839,051
Billed kWh per Customer	8,975	8,395	9,445	6,930	9,011	8,173
Distribution Revenue per Customer	$ 297	$ 341	$ 286	$ 248	$ 297	$ 299
General Service <50kW Customers						
Number of Customers	658	66,167	8,578	777	5,385	1,692
Billed kWh	23,947,776	2,168,823,277	303,109,577	16,076,865	185,040,278	54,185,000
Distribution Revenue	$ 560,330	$ 65,651,135	$ 6,556,945	$ 353,847	$ 3,825,098	$ 1,006,561
Billed kWh per Customer	36,395	32,778	35,336	20,691	34,362	32,024
Distribution Revenue per Customer	$ 852	$ 992	$ 764	$ 455	$ 710	$ 595
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	88	13,668	1,057	31	665	175
Number of Large Users	0	50	5	0	1	1
Number of Sub Transmission Customers	0	0	0	0	0	0
Billed kWh	114,774,177	17,202,658,800	1,242,613,503	24,869,234	817,368,060	203,636,839
Distribution Revenue	$ 758,196	$ 212,331,728	$ 9,344,614	$ 255,366	$ 7,508,059	$ 1,671,334
Billed kWh per Customer	1,304,252	1,254,021	1,170,069	802,233	1,227,279	1,157,027
Distribution Revenue per Customer	$ 8,616	$ 15,478	$ 8,799	$ 8,238	$ 11,273	$ 9,496
Unmetered Scattered Load Connections						
Number of Connections	64	1,105	924	48	539	213
Billed kWh	427,340	55,244,974	5,942,432	285,569	200,468	1,128,127
Distribution Revenue	$ 23,650	$ 3,190,306	$ 193,156	$ 8,107	$ 116,592	$ 47,891
Billed kWh per Connection	6,677	49,995	6,431	5,949	372	5,296
Distribution Revenue per Connection	$ 370	$ 2,887	$ 209	$ 169	$ 216	$ 225

Statistics by Customer Class For the year ended December 31, 2010	Wellington North Power Inc.	West Coast Huron Energy Inc.	West Perth Power Inc.	Westario Power Inc.	Whitby Hydro Electric Corporation	Woodstock Hydro Services Inc.
Residential Customers						
Number of Customers	3,095	3,237	1,794	19,301	37,283	13,701
Billed kWh	25,303,871	26,431,108	16,271,614	216,435,358	364,548,865	110,101,647
Distribution Revenue	$ 857,961	$ 1,072,220	$ 421,926	$ 5,351,731	$ 12,252,235	$ 3,959,449
Billed kWh per Customer	8,176	8,165	9,070	11,214	9,778	8,036
Distribution Revenue per Customer	$ 277	$ 331	$ 235	$ 277	$ 329	$ 289
General Service <50kW Customers						
Number of Customers	473	483	235	2,429	1,967	1,170
Billed kWh	11,368,653	14,687,390	7,816,746	66,420,789	75,513,331	42,052,194
Distribution Revenue	$ 293,374	$ 373,791	$ 134,781	$ 1,191,205	$ 1,758,047	$ 815,564
Billed kWh per Customer	24,035	30,409	33,263	27,345	38,390	35,942
Distribution Revenue per Customer	$ 620	$ 774	$ 574	$ 490	$ 894	$ 697
General Service >50kW, Large User (>5000kW) and Sub Transmission						
Number of GS >50kW Customers	45	49	20	277	419	203
Number of Large Users	0	1	0	0	0	0
Number of Sub Transmission Customers	0	0	0	0	0	0
Billed kWh	58,906,580	97,013,288	35,413,140	190,213,516	410,991,175	218,923,674
Distribution Revenue	$ 522,349	$ 816,177	$ 229,938	$ 1,725,696	$ 3,760,211	$ 1,528,407
Billed kWh per Customer	1,309,035	1,940,266	1,770,657	686,691	980,886	1,078,442
Distribution Revenue per Customer	$ 11,608	$ 16,324	$ 11,497	$ 6,230	$ 8,974	$ 7,529
Unmetered Scattered Load Connections						
Number of Connections	3	4	4	63	390	135
Billed kWh	10,099	84,324	16,319	323,110	1,940,522	562,716
Distribution Revenue	$ 244	$ 3,927	$ 76	$ 20,899	$ 106,365	$ 26,850
Billed kWh per Connection	3,366	21,081	4,080	5,129	4,976	4,168
Distribution Revenue per Connection	$ 81	$ 982	$ 19	$ 332	$ 273	$ 199

Glossary of Terms

FINANCIAL INFORMATION

	Aggregation of Trial Balance (RRR section 2.1.7) accounts
Cash & cash equivalents	1005-1070
Receivables	1100-1170
Inventory	1305-1350
Inter-company receivables	1200 + 1210
Other current assets	1180 + 1190 + 2290 if debit balance + 2296 if debit balance
Property plant & equipment	1605-2075
Accumulated depreciation & amortization	2105-2180
Regulatory assets (net)	1505-1595 + 2405 + 2425
Inter-company investments	1480-1490
Other non-current assets	1405-1475 + 2350 if debit balance
Accounts payable & accrued charges	2205-2220 + 2250-2256 + 2294
Future income tax liabilities - current	2296 if credit balance
Other current liabilities	2264 + 2285-2292 if credit balance
Inter-company payables	2240 + 2242
Loans and notes payable, and current portion of long-term debt	2225+ 2260-2262 + 2268-2272
Long-term debt	2505-2525
Inter-company long-term debt & advances	2530 + 2550
Regulatory liabilities (net)	1505-1595 + 2405 + 2425
Other deferred amounts & customer deposits	2305 + 2308-2348 + 2410 + 2415 + 2435
Employee future benefits	2306
Future income tax liabilities	2350 if credit balance
Shareholders' equity	3005-3065
Power and distribution revenue	4006-4245
Cost of power and related costs	4705-4750
Other income	4305-4415+ 6305
Operating expense	4505-4565 + 4805-4850 + 5005-5096
Maintenance expense	4605-4640 + 4905-4965 + 5105-5195
Administrative expense	5305-5695
Other expense	5205-5215 + 6105 + 6205-6225 + 6310-6415
Depreciation and amortization expense	5705-5740
Financing expense	6005-6045
Current income tax	6110
Future income tax	6115

Glossary of Terms

FINANCIAL RATIOS

Liquidity Ratios measure the availability of cash to pay debt.

Current Ratio is a financial ratio that measures whether or not a firm has enough resources to pay its debts over the next 12 months.

Leverage Ratios are the financial statement ratios which show the degree to which the business is leveraging itself through its use of borrowed money.

Debt Ratio is long-term debt over total assets.

Debt to Equity Ratio is long-term debt over total equity.

Interest Coverage Ratio is used to determine a firm's ability to pay interest on outstanding debt.

Profitability Ratios measure the firm's use of its assets and control of its expenses to generate an acceptable rate of return.

Return on Equity measures the actual rate of return on the balance sheet shareholders' equity.

Glossary of Terms

Population Served is the estimated number of people served as customers of the utility.

Municipal Population is the Stats Canada population of the municipalities served. May not equal Population Served as other utilities may also serve the same community.

Seasonal Population represents cottagers etc.

Residential Customers applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation.

General Service < 50 kW Customers applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 4,999 kW Customers applies to a non residential account whose average monthly maximum demand used for billing purposes is greater than, or is forecast to be greater than, 50 kW but less than 5,000 kW.

Large User Customers applies to an account whose average monthly maximum demand used for billing purposes is greater than, or is forecast to be greater than, 5,000 kW.

Sub Transmission applies to an account who has embedded supply to Local Distribution Companies or an account that is directly connected to and supplied by the Distributors assets.

Unmetered Scattered Load refers to certain instances where connections can be provided without metering.

Total kWh Purchased represents total kWhs of electricity that has flowed into the distributor's distribution system from the IESO-controlled grid or from a host distributor and from all embedded generation facilities.

Total kWh Delivered (excluding losses) represents the total kWhs of electricity delivered to all customers in the distributor's licensed service area and to any embedded distributors.

Total Distribution Losses (kwh) is the sum of distribution system line losses, metering error and energy theft.

Winter Peak (kW) is the peak load on the distributor system from October to March.

Summer Peak (kW) is the peak load on the distributor system from April to September.

Average Peak (kW) is the average of daily peaks throughout the year.

Capital Additions represents the investment for assets placed in-service. It is the sum of employee labour including benefits, equipment and materials, capital works/other, overhead and carrying charges.

Billed kWh (meter read) refers to the yearly billed kWhs without the loss factor.

Glossary of Terms

SERVICE QUALITY REQUIREMENTS

Low Voltage Connections is the percentage of new low voltage (<750 Volts) connection requests where the connection is made within 5 working days of all prerequisites (engineering, safety, etc.) being met. Must be met 90% of the time.

High Voltage Connections is the percentage of new high voltage (>=750 Volts) connection requests where the connection is made within 10 working days of all prerequisites (engineering, safety, etc.) being met. Must be met 90% of the time.

Telephone Accessibility is the percentage of calls to the utility's general inquiry number that are answered in person within 30 seconds. Must be met 65% of the time.

Appointments Met is the percentage of appointments met where customer presence is required. Must be met 90% of the time.

Written Response to Enquiries is the percentage of customer inquiries relating to a customer's account and requiring a written response where the response is provided within 10 working days of receipt of the inquiry. Must be met 80% of the time.

Emergency Urban Response is the percentage of emergency (fire, police, etc.) trouble calls where a qualified service person is on site within 60 minutes of the call. Urban areas are defined by the respective municipality. Must be met 80% of the time.

Emergency Rural Response is the percentage of emergency (fire, police, etc.) trouble calls where a qualified service person is on site within 120 minutes of the call. Rural areas are defined by the respective municipality. Must be met 80% of the time.

Telephone Call Abandon Rate is the percentage of qualified calls (abandoned after 30 seconds) to a distributor's customer care telephone number that are abandoned before they are answered. Must be less than 10%.

Appointment Scheduling is the percentage of when a customer requests an appointment with a distributor, the distributor shall schedule the appointment to take place with in 5 business days. Must be met 90% of the time.

Rescheduling a Missed Appointment is the percentage of missed appointments that the customer is contacted within 1 business day to reschedule the appointment. Must be met 100% of the time.

SAIDI is the average forced sustained interruption duration per customer served per year (measured in hours). Calculation is "Total Customer Hours of Interruptions" divided by "Total Number of Customers".

SAIFI is the average number of forced sustained interruptions experienced per customer served per year (measured in outages). Calculation is the "Total Customer Interruptions" divided by "Total Number of Customers".

CAIDI is the average forced sustained interruption duration experienced by interrupted customers per year (measured in hours). Calculation is SAIDI divided by SAIFI.

Loss of Supply Adjusted Service Reliability Indices exclude outages caused by a loss of supply. Loss of supply refers to customer interruptions due to problems in the bulk electricity supply system. For this purpose, the bulk electricity supply system is distinguished from the distributor's system based on ownership demarcation.

C

CALCULATION OF THE SMC

76. The calculation of the "per customer" SMC is summarized as follows:

$$\text{SMC} = \frac{(\text{Revenue Requirement / Total number of Residential and General Service <50kW Customers})}{\text{Number of Collection Periods}}$$

$$\$0.806 = \frac{(\$251{,}520{,}340 \ / \ 4{,}730{,}890)}{66}$$

77. Each of the components for the formula is discussed below.

78. *Revenue Requirement:* The SME has applied for a revenue requirement of $251,520,340 as detailed in Exhibit C-1.

79. *Total number of Residential and General Service <50kW Customers:* The "per customer" count used by the SME for the purpose of the SMC is the total number of Residential and General Service <50kW Customers listed for each LDC in the 2010 OEB Electricity Distributor Yearbook (the "2010 Yearbook") published on September 10, 2011. The 2010 Yearbook lists a total of 4,314,896 Residential Customers and 415,994 General Service <50kW Customers (for a total 4,730,890).

A copy of the 2010 Yearbook is included in the SME's pre-filed evidence as Appendix "A" to this Exhibit.

80. The categories of Residential and General Service <50kW Customers were selected by the SME because they provide a reasonably accurate representation of an LDC's customers that will be receiving service from the MDM/R. When all of the province's LDCs are receiving service from the MDM/R, it is expected that meter reads from approximately 4.7 million smart meters will be processed by the MDM/R on a daily basis.

81. The OEB Electricity Distributor Yearbook is compiled from data submitted to the Board by the LDCs through the Board's Reporting and Record-Keeping Requirements and as such the SME considers this data to be accurate and reliable.

82. The SMC was calculated using the number of Residential and General Service <50kW Customers in the 2010 Yearbook. The SME is seeking approval for an automatic adjustment mechanism to adjust the ongoing charge per customer at the beginning of each collection year to reflect the actual number of Residential and General Service <50kW Customers listed in the most recent Yearbook. At the beginning of each collection year the SME will adjust the ongoing fee with the updated number of customers and seek approval from the OEB to advise the LDCs of the adjusted rate to be charged in the new collection year without the need for a hearing.

83. *Number of Collection Periods:* The SME proposes to collect the SMC on a monthly basis, starting July 1, 2012 and ending December 31, 2017. This amounts to 66 collection periods. The SMC will be invoiced for the applicable month on

the tenth business day after the end of the previous month, such that it would be paid by the LDC in the applicable month.

D

MISCELLANEOUS MATTERS

SMC Variance Account

84. The SME's actual costs may vary from the assumptions used to calculate the SMC. As a result, there will likely be either an over-collection or under-collection of revenue by the SME. Accordingly, the SME is seeking Board approval for the establishment of a variance account to deal with changes in its costs, or any revenue surplus or deficiency in respect of the MDM/R.

Pass Through of the SMC

85. During the stakeholder consultation process for the SME/LDC Agreement, distributor representatives expressed concern that they would be subscribing to a new service without knowing whether they would be able to pass through the costs of that service to their ratepayers.

86. Under the SME/LDC Agreement presented to the Board for approval, the SME committed that it would request that the Board permit distributors to pass through the SMC to consumers. A copy of the SME/LDC Agreement is included in the pre-filed evidence as Exhibit D-2. Given that these costs covered by the SMC are already subject to review by the Board in this proceeding, the SME believes a further prudence review is unnecessary when Board orders are issued to distributors for pass through rates.

87. In preparing this application, the SME has consulted with the EDA and LDC representatives. Since the SME/LDC Agreement was finalized in consultation with the EDA and LDCs, the SME was advised by the EDA and LDC representatives that the utilities anticipate proposing that the Board initiate a proceeding on its own motion to issue an order to implement recovery of the then-approved SMC in the rates of all distributors, in order to avoid the inefficiencies inherent in requiring every utility to file its own application for that rate component. While this would be a separate proceeding with evidence filed by the EDA and other stakeholders, the EDA will request that such a proceeding be heard in sequence with this proceeding because the issues are closely related. The SME will support this request to permit distributors to pass through the SMC to their customers.

Service Level Credits

88. The MDM/R Agreement entitles the SME to certain service credits if IBM Canada fails to meet the required service levels.

89. As part of the SME/LDC Agreement presented to the Board for approval the SME has undertaken to collect all service credits paid by IBM Canada into a common account, the balance of which will be reported to the SME Steering Committee (provided for by the SME/LDC Agreement and described in more detail in Exhibit D-1). The SME will also provide supporting information to the SME Steering Committee regarding each incident that resulted in a service credit and the SME Steering Committee will determine both a methodology and the amount of any allocation to individual distributors. Any credits received by individual distributors would be dealt with through their own variance accounts.

4

A

SUMMARY OF THE SME/LDC AGREEMENT

90. The SME is seeking Board approval to use the SME/LDC Agreement for all LDCs that receive service from the MDM/R. The implementation of a standard agreement will ensure that all LDCs in the province will receive non-discriminatory service from the MDM/R.

91. The use of a standard agreement for all of the province's LDCs is grounded in section 5.4 of the Distribution System Code which states:

> **5.4 Agreement with SME or IESO Relating to Metering**
>
> 5.4.1 A distributor shall, upon being requested to do so, enter into an agreement with the Smart Metering Entity or the IESO, in a form approved by the Board, which sets out the respective roles and responsibilities of the distributor and the Smart Metering Entity or the IESO in relation to metering and the information required to be exchanged to allow for the conduct of these respective roles and responsibilities.

92. The SME, in consultation with LDC representatives and the EDA, has developed the SME/LDC Agreement and the subordinate MDM/R Terms of Service. Since June 2007, the SME has been consulting with LDC representatives and the EDA in the development of the SME/LDC Agreement. These consultations included representatives from LDCs identified in Ontario Regulations 427/06 (*Smart Meters: Discretionary Metering Activities and Procurement Principles*) and 428/06 (*Priority Installations*) as early adopters of smart meters.

93. This Exhibit contains an overview of the principles on which the SME/LDC Agreement is premised and a review of select terms of the SME/LDC Agreement.

Principles Underlying the SME/LDC Agreement

94. In drafting and negotiating the SME/LDC Agreement, the SME was guided by the following four principles:

(a) *The MDM/R provides a valuable service to customers across Ontario* – The MDM/R has an important role to play in meeting Ontario's conservation goals. By enabling the use of smart meters and time-of-use pricing, the MDM/R will provide the province's electricity consumers with the tools needed to manage their electricity usage. Moreover, the data in the MDM/R will be an important source of information on the consumption patterns of Ontario consumers.

(b) *The IESO's role as SME is transitional* - The SME has been granted a mandate to bring the MDM/R into operation, in cooperation with the province's LDCs, and ensure that operations are smoothly transferred to any future SME. The provisions of the SME/LDC Agreement must be viewed in this context.

(c) *The SME/LDC relationship is not a standard commercial relationship* – The relationship between the SME and the LDCs is a unique one that is subject to a number of constraints not present in standard commercial relationships. Notably, as the counterparty to IBM Canada in the MDM/R Agreement (and any future operational service provider ("OSP")), the SME effectively acts as a contract manager on behalf of all LDCs, but is also constrained by the provisions of the MDM/R Agreement. Further, the activities of both the SME and the LDCs are ultimately subject to oversight and regulation by this Board and the parties are required to enter into an agreement by the Distribution System Code.

(d) *The SME/LDC Agreement must be flexible* - While the SME/LDC Agreement applies only to LDCs (access to the MDM/R by non-LDCs will be governed by a separate agreement to be completed in the future), it will be used with over 70 parties and must be flexible enough to cover their individual circumstances. Moreover, the SME/LDC Agreement must respond to the ongoing development of the MDM/R without requiring either the SME or the LDCs to frequently apply to the Board for amendments.

Structure of the SME/LDC Agreement and MDM/R Terms of Service

95. The governing documentation for the MDM/R is modeled on the hierarchal framework of documents for the wholesale market (Participation Agreement, Market Rules and Market Manuals) that has been used successfully by the IESO and is familiar to other market participants including LDCs. In particular:

(a) *The SME/LDC Agreement* - The SME and LDCs will enter into a standard SME/LDC Agreement under section 5.4.1 of the *Distribution System Code* that will set out the high level principles governing the operation of the MDM/R and the SME/LDC relationship. The SME used its existing Participation Agreement for the wholesale market as a template on which to structure the

SME/LDC Agreement and adopted the approach taken in the wholesale market of a standard form agreement that sets out high level principles and binds the parties to a set of governing rules (in this case, the MDM/R Terms of Service).

(b) *MDM/R Terms of Service* – Under the proposed SME/LDC Agreement, the SME will have the authority to publish the MDM/R Terms of Service, a standard set of rules outlining the operational details of the MDM/R, that will apply to all MDM/R service recipients. The MDM/R Terms of Service will provide for the creation of subordinate level documentation that will contain much of the detail of the operation of the MDM/R. The SME does not require and is not seeking Board approval of the MDM/R Terms of Service in this application so as to maintain the flexibility to amend the MDM/R Terms of Service without requiring a subsequent application to the Board. A draft of the Terms of Service has been included in this application as Exhibit D-3 for information purposes only.

(c) *MDM/R Manuals and Procedures* - The MDM/R Manuals and Procedures will augment the MDM/R Terms of Service with a set of operational instructions.

Roles and Responsibilities

96. Section 5.4.1 of the Distribution System Code states that the agreement approved by the Board will set out "the respective roles and responsibilities of the distributor and the Smart Metering Entity or the IESO in relation to metering and the information required to be exchanged to allow for the conduct of these

respective roles and responsibilities." The respective roles and responsibilities of the SME and an LDC are detailed in Article 2 of the SME/LDC Agreement.

97. One of the objects of the SME specified in section 53.8 of the *Electricity Act* is to "collect and manage and to facilitate the collection and management of information and data and to store the information and data related to the metering of consumers' consumption or use of electricity in Ontario, including data collected from distributors". Consistent with this object, the SME's responsibilities include the following:

(a) administering the development of the MDM/R (section 2.2.1 and 2.2.2);

(b) conducting testing of the MDM/R and interfaces between the MDM/R and an LDC's system and cooperating with reasonable testing required by the LDC (sections 2.2.3 and 2.2.4);

(c) providing training and technical support (section 2.2.5 and 2.2.8)

(d) overseeing the operations of the MDM/R (sections 2.2.6, 2.2.7, 2.2.9, 2.2.10); and

(e) transitioning to any subsequent agreement relating to MDM/R operations (section 2.2.11).

98. Under section 53.15 of the *Electricity Act*, LDCs have a reciprocal obligation to "provide the Smart Metering Entity with such information as it requires to fulfil its objects or conduct its business activities." The roles and responsibilities of the LDC that flow from this obligation include:

(a) ensuring its smart metering systems comply with applicable functional and technical specifications (section 2.6.1);

(b) participating in testing of the MDM/R and interfaces between the MDM/R and an LDC's system and certifying successful completion of testing (sections 2.6.2 and 2.6.3); and

(c) the transmission of smart metering data to the SME (section 2.6.4).

99. The scope and wording of the respective roles and responsibilities of the SME and an LDC specified in Article 2 are the product of extensive discussions with LDC representatives. The SME believes the language strikes an appropriate balance that ensures successful operation of the MDM/R while protecting the interests of both the SME and the LDCs.

SME Steering Committee

100. Under section 3.2 of the SME/LDC Agreement, the SME is obligated to establish the SME Steering Committee as a forum to represent stakeholders. The SME Steering Committee is modeled on the IESO Technical Panel, with which both the IESO and LDCs have had considerable experience.

101. The SME Steering Committee will have 13 members who will be appointed by the Board of Directors of the SME from nominations made by any person eligible to receive service from the MDM/R and the Board of Directors of the EDA. A majority of the members of the SME Steering Committee will be LDC representatives. In response to feedback from LDCs, the role and composition of the SME Steering Committee was entrenched into the SME/LDC Agreement such that Board approval would be required to amend these provisions.

102. The primary role of the SME Steering Committee will be to provide stakeholder input to the SME on the administration and operation of the MDM/R. Section 3.4 of the SME/LDC Agreement provides that the SME may not amend the MDM/R Terms of Service without seeking the advice and recommendation of the SME Steering Committee on the amendment. Also, any party seeking to amend the SME/LDC Agreement must first consult with the SME Steering Committee on the merits of its proposal under section 10.1 before it can apply to the Board for approval of the amendment. As discussed in more detail below, the SME Steering Committee will also be responsible for providing advice to the SME in the development of a protocol for access to MDM/R data, the allocation of service credits received from IBM Canada or any other OSP, and planning for the transition to a new SME.

MDM/R Terms of Service

103. Section 3.1 of the SME/LDC Agreement contemplates that the SME may establish MDM/R Terms of Service to govern operational aspects of the MDM/R. As noted above, the MDM/R Terms of Service will be subordinate to the SME/LDC Agreement.

104. Under section 3.4, the SME has the authority, in consultation with the SME Steering Committee, to amend the MDM/R Terms of Service. This flexibility will permit modification of operational matters connected to the MDM/R without returning to the Board for an amendment to the LDC/SME Agreement.

105. LDC representatives advised the SME that access to the Board was essential given the Board's role in regulating the activities of both the SME and the province's LDCs. During these consultations, a concern was expressed about

the absence of an explicit statutory or regulatory mechanism that would allow the LDCs to appeal an amendment to the MDM/R Terms of Service to the Board as there is no legislative equivalent to the market rule review process in section 33 of the *Electricity Act*.

106. In response to this concern, the SME has fashioned a solution under which an LDC seeking review of an amendment to the MDM/R Terms of Service could gain access to the Board by bringing an application to amend the SME/LDC Agreement (which would in effect override an amendment to the MDM/R Terms of Service).

Smart Metering Charge

107. Under section 2.3 of the SME/LDC Agreement, the SME will charge LDCs a Board-approved SMC for the services provided by the SME and the MDM/R.

108. To minimize costs for the IESO and LDCs, the SME/LDC Agreement provides that the SMC be charged to LDCs and collected using the established IESO settlement procedures under the Market Rules. LDC representatives consulted by the SME agreed that using the existing IESO settlement process for the wholesale market to invoice and collect the SMC was preferable to incurring the additional cost of creating and operating a separate billing system for the SMC.

109. The IESO Market Rules were amended effective December 12, 2007 to permit the collection of the SMC by the IESO. A copy of Market Rule amendment MR-00336: Settlements - Treatment of Smart Metering Charge, as approved by the IESO Board of Directors, is attached to this exhibit as Appendix "A". These amendments also ensure that there are adequate measures in place

to protect the integrity of the IESO's settlement systems. A copy of a Q&A document addressing questions raised by the Technical Panel in connection with the market rule amendment is attached as Appendix "B" to this exhibit.

Audit Requirements

110. The audit requirements for the MDM/R were negotiated separately between the SME's audit staff and representatives of Hydro One. As Hydro One is subject to certain audit requirements as a reporting issuer, representatives from other LDCs were confident that a provision sufficient to satisfy Hydro One's audit requirements will suffice for all LDCs. The proposed language of section 2.4 of the SME/LDC Agreement has been reviewed and approved by Hydro One.

Access to MDM/R Data

111. The MDM/R will contain important data on the use of electricity in the province and paragraph 4 of section 53.18 of the *Electricity Act* requires the SME to "provide and promote non-discriminatory access, on appropriate terms and subject to any conditions in its licence relating to the protection of privacy, by distributors, retailers, the OPA and other persons."

112. The balance of providing access to third parties while protecting the privacy of consumers was recognized when developing the SME/LDC Agreement. Section 5.1 sets out the general principle that the SME may make data in the MDM/R available to third parties, but can only do so if the data is "presented in a manner that prevents the specific data of an individual customer of the Distributor being identified with that customer or premises." As provided for in section 5.2, the SME will consult with the SME Steering Committee to

develop a protocol for access to MDM/R data that balances these two competing interests.

Liability and Indemnification

113. Article 7 of the SME/LDC Agreement addresses the issues of liability and indemnification. Subject to the exceptions discussed below, section 7.1 limits the liability of the SME to actual direct damages and provides that the cumulative liability of the SME to all MDM/R service recipients for any act or omission of the SME shall not exceed an aggregate of $1,000. Similarly, section 7.2 limits the liability of the Distributor to the SME to actual direct damages and provides a liability cap of $1,000 for any act or omission.

114. The SME/LDC Agreement contains an exception to the general limitation of liability on the part of the SME for indemnification of any claims arising due to a breach by the SME of Article 5 (Access to MDM/R Data) of the SME/LDC Agreement. This carries through from the MDM/R Agreement, which is an exception to the limitation on IBM Canada's liability for, amongst other things, breaches of confidentiality and privacy.

115. In recognition of the unique nature of the SME/LDC relationship, section 7.5 obligates the SME to cooperate with an LDC in any proceeding before the Board in which the LDC seeks a change to any of its rates or charges or other appropriate relief for any of its losses or incremental costs related to any act or omission of the SME or an OSP (including IBM Canada). Such cooperation by the SME shall include, but not be limited to, promptly providing to the Distributor and the OEB, at the request of the Distributor but at the SME's cost, accurate information, analysis, documents and evidence. For greater certainty,

the SME's obligation to provide assistance under this section is not limited to a cost of $1,000.

116. Under section 7.7 of the SME/LDC agreement the SME is obligated to, at the SME's cost, use commercially reasonable efforts to monitor each OSP's performance and enforce the provisions of their agreements with the SME.

117. The provisions of Article 7 ensure that the parties to the SME/LDC Agreement bear full responsibility for fulfilling their obligations while limiting the SME's and LDCs' exposure to damages. The SME believes the proposed approach to liability is appropriate in light of the regulated nature of both the SME and the LDCs. Both the IESO and the SME operate on a non-profit basis and have limited assets which are vital for the operation of Ontario's electricity system. As such, any liability attributed to the IESO or the SME would ultimately be passed back to LDCs through increases in the SMC.

118. The issue of liability was the subject of extensive discussions with the EDA and LDC representatives. It is the understanding of the SME that the EDA will support the proposed approach to liability if the Board: (i) explicitly endorses the proposed approach to liability; and (ii) provides LDCs with a regulatory mechanism to promptly recover through rates any costs incurred by an LDC in the event of an MDM/R failure that disrupts the LDC's operations. Such a mechanism will provide potential lenders with the assurance necessary to allow an LDC access to the financial and other resources that would be required to respond to such a failure. The LDC community expressed a concern that, without such a mechanism, it could be difficult for some LDCs to access emergency funding to enable their continued operation, and credit ratings could be impacted.

119. The SME has also been advised by the EDA that the EDA anticipates requesting that the Board approve a deferral account for all distributors to record prudent costs incurred as result of an MDM/R failure or to manage the risks of such a failure. The SME supports this request but is not in a position to lead substantive evidence on the matter.

Allocation of Service Credits

120. Under Section 2.2.10 of the SME/LDC Agreement, the SME is obligated to "make its best efforts to ensure the MDM/R services meet the applicable service levels prescribed in the MDM/R Terms of Service". The service levels for the MDM/R will mirror the service levels that IBM Canada must meet under the MDM/R Agreement and are specified on a province-wide basis (as opposed to per LDC). If IBM Canada fails to meet these service levels, the SME will receive service credits from IBM Canada to reduce the fees owing to IBM Canada under the MDM/R Agreement.

121. All service credits received by the SME will be passed on to LDCs through credits against the SMC. Under section 7.6 of the SME/LDC Agreement, the SME will report the amount of any accrued service credits from IBM Canada (or any other OSP) to the SME Steering Committee along with supporting information on each incident that resulted in a service credit. The SME Steering Committee will then determine the allocation of any credits to any MDM/R service recipients. This will allow the SME Steering Committee to use discretion in distributing the credits in circumstances where one or more users of the MDM/R have been disproportionately affected by a service level failure.

Dispute Resolution

122. A key issue raised during meetings with LDCs was an appropriate mechanism to settle any disputes between the SME and the LDCs. LDCs expressed a desire to have any disputes related to the SME/LDC Agreement settled by the Board. As such, the SME/LDC Agreement contains a provision in section 8.1 that permits either party, after attempting good faith negotiations, to apply to the Board for determination of a dispute.

123. The Board has the jurisdiction to determine such disputes under section 19 of the *OEB Act*, which provides the Board with the "authority to hear and determine all questions of law and of fact" in all matters within its jurisdiction. The Board is also the most appropriate arbiter of such disputes because of its authority over the SME/LDC Agreement under section 5.4 of the Distribution System Code and its ongoing regulatory oversight of both the SME and the province's LDCs.

124. An exception to the dispute resolution process described above is contained in section 8.3 of the SME/LDC Agreement for disputes with respect to the calculation of the SMC amount; such disputes will instead proceed using the existing dispute mechanism procedures contained in the IESO Market Rules for IESO settlement statements. The Market Rules outline a detailed process for good faith negotiation followed by arbitration. The adoption of this process creates a single consistent approach for resolving disputes concerning an IESO settlement statement whether the charges relate to the wholesale market or the SMC. To date, the IESO has not had a settlement statement dispute under the Market Rules proceed beyond good faith negotiation.

Amendments

125. As provided for in section 10.1, no amendment to the SME/LDC Agreement is effective until approved by the Board. The provision also requires that any party seeking to amend the SME/LDC Agreement must first consult the SME Steering Committee on the merits of the proposed amendment.

Term

126. The SME/LDC Agreement terminates on January 26, 2016, which is aligned with the end of the current SME licence granted by the Board. The term of the SME/LDC Agreement can only be extended by order of the Board.

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Market Rule Amendment Proposal

Part 1 – Market Rule Information

Identification No.:	**MR-00336-R00**		
Subject:	**Settlements**		
Title:	**Treatment of the Smart Metering Charge**		
Nature of Proposal:	☐ Alteration	☐ Deletion	☒ Addition
Chapter:	9	Appendix:	
Sections:	6.11		
Sub-sections proposed for amending:			

Part 2 – Proposal History

Version	Reason for Issuing	Version Date
1.0	Draft for Technical Panel Review	August 22, 2007
2.0	Published for Stakeholder Review and Comment	August 30, 2007
3.0	Draft for Technical Panel Review	September 12, 2007
4.0	Published for Stakeholder Review and Comment	September 20, 2007
5.0	Published for Technical Panel Vote	October 9, 2007
6.0	Recommended by Technical Panel and Submitted for IESO Board Approval	October 16, 2007
7.0	Approved by IESO Board	November 15, 2007
Approved Amendment Publication Date:	November 16, 2007	
Approved Amendment Effective Date:	December 12, 2007	

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Provide a brief description of the following:

- The reason for the proposed amendment and the impact on the *IESO-administered markets* if the amendment is not made.
- Alternative solutions considered.
- The proposed amendment, how the amendment addresses the above reason and impact of the proposed amendment on the *IESO-administered markets*.

Summary

The amendment proposes to allow for use of the wholesale market settlement, invoicing and payment process for the smart metering services provided by the IESO to local distribution companies. The proposed amendment would allow the IESO to instruct the bank to debit the IESO-administered markets settlement clearing account only the amount paid for the smart metering charge and deposit those funds in an IESO operating account.

These amendments would simplify the smart metering charge settlement, invoicing and payment process by using the current wholesale market processes. As the Smart Metering Initiative is not part of the wholesale market, the obligation to pay and resulting actions due to non-payment of this charge would be included in agreements between the IESO and the LDCs. It is the IESO's intention that this agreement would authorize the use of wholesale market rules and processes regarding settlements and dispute resolution. This agreement will not make the LDCs that are not market participants subject to the market rules. Rather the LDCs will be agreeing to use certain existing processes defined by the market rules where applicable.

The issue of incomplete payments by market participants paying the smart metering charge is addressed in MR-00336-R01.

Background

The Smart Metering Initiative (SMI) is the Government of Ontario's initiative to create a conservation culture and a toolset for demand management based upon the province-wide deployment of smart meters. The smart meter will record electricity use for each hour and apply time-of-use pricing for Ontario consumers. This will, in effect, allow the consumer to manage their electricity use and take advantage of lower pricing periods.

The IESO entered into an agreement in July 2006 with the Ministry of Energy to support the SMI and was recently designated as the Smart Metering Entity (SME) by regulation under the Electricity Act, 1998.[1] As the SME, the IESO is responsible for the administration and operation of the meter data management / meter data repository (MDM/R), which will collect and store information related to the metering of consumers' consumption or use of electricity in Ontario,. The SME will also provide the validating, estimating and editing process for this data so that it can used by the LDCs for billing purposes. The *Electricity Act, 1998*, as amended by Bill 21, entitles the SME to recover, through just

[1] Refer to the Ministry of Energy's announcement at http://www.e-laws.gov.on.ca/html/source/regs/english/2007/elaws_src_regs_r07393_e.htm

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

and reasonable rates and the costs approved by the OEB associated with the conduct of the SME's activities. The OEB has not yet established a fee or fee structure for the SME function. This OEB-established fee would be the smart metering charge.

In June 2007, the OEB issued amendments to the Distribution System Code that require LDCs to enter into an agreement with the SME, in a form approved by the OEB. The agreement will set out the respective roles and responsibilities of the LDC and the SME in relation to metering and the information required to be exchanged to allow for the conduct of these respective roles and responsibilities. The IESO, as the SME, has circulated a draft agreement to the LDCs for comment and will be pursuing OEB approval of the agreement in the late summer/early fall of 2007.

For further information refer to MR-00336-Q00.

Discussion

It is proposed to add a new section, 6.11.4a, which would permit the IESO to instruct the bank to debit the IESO settlement clearing account the amount paid by the LDCs for the smart metering charge. The proposed amendment would also permit the IESO to instruct the bank to deposit these funds into an IESO operating account.

PART 4 – PROPOSED AMENDMENT

Chapter 9:

Chapter 9:

6.11 Payment of Invoices

6.11.1 Subject to section 6.11.2 and section 11.5 of Chapter 2, each *market participant* shall pay the full net *invoice* amount by the *market participant payment date* specified in the *SSPC* or, where applicable, determined in accordance with any of sections 6.3.23, 6.3.27 and 6.3.29, regardless of whether or not the *market participant* has initiated or continues to have a dispute respecting the net amount payable.

6.11.2 A *market participant* may pay at an earlier date than the *market participant payment date* specified in the *SSPC* or, where applicable, determined in accordance with any of sections 6.3.23, 6.3.27, and 6.3.29 in accordance with the following:

6.11.2.1 notification must be given to the *IESO* before submitting such prepayment or before converting an existing overpayment by the *market participant* into a prepayment;

6.11.2.2 the prepayment notification shall specify the dollar amount prepaid;

6.11.2.3 a prepayment shall be made by the *market participant* into the *IESO prepayment account* designated by the *IESO*;

6.11.2.4 on any *market participant payment date,* the *IESO* may initiate the transfer of necessary funds from the *IESO*'s *prepayment account* to the *IESO settlement clearing account* to discharge, up to the amount of the prepayment, that *market participant*'s outstanding payment obligations arising in relation to that *market participant payment date;* and

6.11.2.5 [Intentionally left blank]

6.11.2.6 [Intentionally left blank]

6.11.2.7 subject to section 5.6.3 of Chapter 2, and notwithstanding section 4.18.1.2 of Chapter 8, funds held in an *IESO prepayment account* on behalf a *market participant* may be applied by the *IESO* to any outstanding financial obligations of that *market participant* to the *IESO* for transactions carried out in the *IESO-administered markets.*

6.11.3 With respect to transmission service charges, the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant transmitter's transmission services settlement account sufficient funds to pay in full the transmission service charges falling due to that transmitter on any *IESO* payment date specified in the SSPC or, where applicable, determined in accordance with any of sections 6.3.23, 6.3.27, and 6.3.29.

6.11.4 With respect to the *IESO administration charge,* the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant *IESO* operating account sufficient funds to pay in full the *IESO administration charge* falling due on any *IESO payment date* specified in the *SSPC* in priority to any other payments to be made on that *IESO payment date* or on subsequent days out of the *IESO settlement clearing account.*

6.11.4a With respect to the smart metering charge, the *IESO* may instruct the bank where the *IESO settlement clearing account* is held to debit the *IESO settlement clearing account* and transfer to the relevant *IESO* operating account only those funds that were received in the *IESO settlement clearing account* in payment of the smart metering charge. The smart metering charge is the fee approved by the *OEB* to recover costs incurred by the *IESO* solely as a result of the *IESO* acting as the Smart Metering Entity and its responsibilities related to the smart metering initiative.

6.11.5 The *IESO* shall, on the *IESO payment date* specified in the *SSPC* or, where applicable, determined in accordance with any of sections 6.3.23, 6.3.27, and 6.3.29, determine the amounts available in the *IESO settlement clearing account* for distribution to *market participants*, and shall, if necessary, borrow funds in accordance with the provisions of section 6.14 if necessary to enable the *IESO settlement clearing account* to clear no later than 11:00 am on the *IESO payment date.*

PART 5 – IESO BOARD DECISION RATIONALE

These amendments would simplify and reduce the costs of the smart metering charge settlement, invoicing and payment processes by using the current wholesale market processes.

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Market Rule Amendment Proposal

PART 1 – MARKET RULE INFORMATION

Identification No.:	MR-00336-R01				
Subject:	**Settlements**				
Title:	**Treatment of the Smart Metering Charge**				
Nature of Proposal:	☐ Alteration		☐ Deletion		☒ Addition
Chapter:	9		Appendix:		
Sections:	6.14				
Sub-sections proposed for amending:					

PART 2 – PROPOSAL HISTORY – REFER TO MR-00336-R00

Version	Reason for Issuing	Version Date
Approved Amendment Publication Date:		
Approved Amendment Effective Date:		

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

Provide a brief description of the following:

- The reason for the proposed amendment and the impact on the *IESO-administered markets* if the amendment is not made.
- Alternative solutions considered.
- The proposed amendment, how the amendment addresses the above reason and impact of the proposed amendment on the *IESO-administered markets*.

Summary

Refer to MR-00336-R00.

This amendment proposes to address the situation where a market participant:

- makes a partial payment on an invoice that contains wholesale market settlement amounts and the smart metering charge; and
- does not direct the IESO how to apportion the partial payment to the wholesale market settlement amounts and the smart metering charge.

This amendment would obligate the IESO to apply the partial payment first to wholesale market settlement amounts owed by the market participant and then apply any remaining payment to the smart metering charge.

This amendment would reduce the risk of a default on payment of wholesale market settlement amounts by a market participant also paying the smart metering charge and the subsequent imposition of a default levy on non-defaulting market participants.

Background

Refer to MR-00336-R00.

When making a payment to one of its creditors, a debtor has the right at law to allocate the payment among the various obligations owed to that creditor. The proposed introduction of the smart metering charge on the same invoice as wholesale market charges requires recognition of the debtor's rights to allocate a partial payment. The situation where the debtor does not exercise its right to allocate a partial payment also needs to be addressed. In this latter situation, it is important that the wholesale market be protected, to the extent possible, from a default of wholesale market charges and the resulting imposition of the default levy.

Discussion

It is proposed to add a new section, 6.14.3A, which would dictate the allocation of funds if there is an incomplete invoice payment. If a market participant fails to pay their invoice in full and the market participant has not advised the IESO as to how to apportion a partial payment, the IESO would be obligated to allocate the partial payment first to satisfying any charges due under the market rules before being applied to the smart metering charge.

This amendment would:

- recognize the right of the market participant to allocate a partial payment,
- provide transparency and certainty as to what would happen when a market participant does

PART 3 – EXPLANATION FOR PROPOSED AMENDMENT

not exercise that right; and

- reduce the risk of a default on wholesale market payments and the resulting imposition of the default levy.

PART 4 – PROPOSED AMENDMENT

Chapter 9

6.14 Payment Default

6.14.1 Subsequent to the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date* referred to in the *SSPC* or, where applicable, determined in accordance with any of sections 6.3.23, 6.3.27, and 6.3.29, the *IESO* shall ascertain if the full amount due by any *market participant* has been remitted to the *IESO settlement clearing account*.

6.14.2 A *market participant* shall notify the *IESO* immediately if it becomes aware that a payment for which it is responsible will not be remitted to the *IESO settlement clearing account* on time and shall provide the reason for the delay in payment.

6.14.3 If the full amount due by a *market participant* has not been remitted after accounting for any prepayments made by the *market participant* pursuant to section 6.11.2, the provisions of section 6.3 of Chapter 3 shall apply and *default interest* shall accrue on all amounts outstanding.

6.14.4 The *IESO* shall be authorised to borrow short-term funds to clear the credits in any settlement cycle only if the following conditions are met:

6.14.4.1 there are insufficient funds remitted into the *IESO settlement clearing account* to pay all *market creditors* due for payment from the funds in the *IESO settlement clearing account,* and clear the *IESO settlement clearing account* on a given *IESO payment date*, due to:

a. payment default by one or more *market participants* in the *day-ahead energy forward market* or the *real-time markets*; or

b. the circumstances referred to in section 4.19.2 or 4.19.6 of Chapter 8;

6.14.4.2 [Intentionally left blank]

6.14.5 If the *IESO* borrows short-term funds pursuant to section 6.14.4, it shall recover this borrowing:

6.14.5.1 where the insufficient funds were due to a payment default referred to in section 6.14.4.1 (a) by taking all steps against the *defaulting market participant* as provided for in these *market rules* and as referred to in section 8.1.2.2 and then, if necessary, by imposing the *default levy* in accordance with section 8 of Chapter 2; or

6.14.5.2 where the insufficient funds were due to the circumstances referred to in section 6.14.4.1 (b), in the manner referred to in sections 4.19.3 and 4.19.5 of Chapter 8 and then, if necessary, by recovering from *market participants*, on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and *intertie metering points* during all intervals and *settlement hours* within the *energy market billing period* in which the *IESO* invoices the *market participants*.

6.14.6 If there are insufficient funds remitted into the *IESO settlement clearing account* to pay all *market creditors* due for payment from the funds in the *IESO settlement clearing account,* and clear the *IESO settlement clearing account* on a given *IESO payment date* due to default by one or more *market participant*s or to the circumstances referred to in section 6.14.4.1 (b), the *IESO* shall borrow funds in accordance with section 6.14.4 in order to clear the *IESO settlement clearing account* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on that *IESO payment date.*

6.14.7 If the *IESO* has exhausted credit availability contemplated by section 6.14.4, then the *IESO* shall pay *real-time market creditors* on a pro rata basis in proportion to the amounts owed to each *real-time market creditor*. Any amounts that remain owing to *real-time market creditors* shall bear interest at the *default interest rate* until paid.

6.14.8 Upon receipt of any payments by the *IESO*, either from or on the behalf of one or more *defaulting market participants* including any *prudential support* held by the *IESO*, or on behalf of *non-defaulting market participants* pursuant to a *default levy*, the *IESO* shall first repay all existing lines of credit and other banking facilities, including the portion of the *deferred payment plan line of credit* applicable to such *defaulting market participants*, and following repayment of such lines of credit and banking facilities, the *IESO* shall then repay on a pro-rata basis all *real-time market creditors* owed amounts pursuant to section 6.14.7.

6.14 Payment Default

6.14.1 Subsequent to the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on the *market participant payment date* referred to in the *SSPC* or, where applicable, determined in accordance with any of sections 6.3.23, 6.3.27, and 6.3.29, the *IESO* shall ascertain if the full amount due by any *market participant* has been remitted to the *IESO settlement clearing account.*

6.14.2 A *market participant* shall notify the *IESO* immediately if it becomes aware that a payment for which it is responsible will not be remitted to the *IESO settlement clearing account* on time and shall provide the reason for the delay in payment.

6.14.3 If the full amount due by a *market participant* has not been remitted after accounting for any prepayments made by the *market participant* pursuant to section 6.11.2, the provisions of section 6.3 of Chapter 3 shall apply and *default interest* shall accrue on all amounts outstanding.

6.14.3A If the *market participant's invoice* includes a *settlement amount* owing for the smart metering charge under section 6.11.4A and the *market participant*:

- fails to remit the full *invoice* amount due by the *market participant payment date*; and
- does not direct the *IESO* how to apportion the payment between the smart metering charge and all other *settlement amounts* on the *invoice* prior to the *IESO payment date*,

the *IESO* shall allocate the payment made by the *market participant* first to satisfying any *settlement amounts* due under the *market rules* before being applied to the smart metering charge.

6.14.4 The *IESO* shall be authorised to borrow short-term funds to clear the credits in any settlement cycle only if the following conditions are met:

6.14.4.1 there are insufficient funds remitted into the *IESO settlement clearing account* to pay all *market creditors* due for payment from the funds in the *IESO settlement clearing account,* and clear the *IESO settlement clearing account* on a given *IESO payment date*, due to:

a. payment default by one or more *market participants* in the *day-ahead energy forward market* or the *real-time markets*; or

b. the circumstances referred to in section 4.19.2 or 4.19.6 of Chapter 8;

6.14.4.2 [Intentionally left blank]

6.14.5 If the *IESO* borrows short-term funds pursuant to section 6.14.4, it shall recover this borrowing:

6.14.5.1 where the insufficient funds were due to a payment default referred to in section 6.14.4.1 (a) by taking all steps against the *defaulting market participant* as provided for in these *market rules* and as referred to in section 8.1.2.2 and then, if necessary, by imposing the *default levy* in accordance with section 8 of Chapter 2; or

6.14.5.2 where the insufficient funds were due to the circumstances referred to in section 6.14.4.1 (b), in the manner referred to in sections 4.19.3 and 4.19.5 of Chapter 8 and then, if necessary, by recovering from *market participants*, on a pro-rata basis across all allocated quantities of *energy* withdrawn at all *RWMs* and *intertie metering points* during all intervals and *settlement hours* within the *energy market billing period* in which the *IESO* invoices the *market participants*.

6.14.6 If there are insufficient funds remitted into the *IESO settlement clearing account* to pay all *market creditors* due for payment from the funds in the *IESO settlement clearing account,* and clear the *IESO settlement clearing account* on a given *IESO payment date* due to default by one or more *market participants* or to the circumstances referred to in section 6.14.4.1 (b), the *IESO* shall borrow funds in accordance with section 6.14.4 in order to clear the *IESO settlement clearing account* no later than the *close of banking business* (of the bank at which the *IESO settlement clearing account* is held) on that *IESO payment date.*

6.14.7 If the *IESO* has exhausted credit availability contemplated by section 6.14.4, then the *IESO* shall pay *real-time market creditors* on a pro rata basis in proportion to the amounts owed to each *real-time market creditor*. Any amounts that remain owing to *real-time market creditors* shall bear interest at the *default interest rate* until paid.

6.14.8 Upon receipt of any payments by the *IESO*, either from or on the behalf of one or more *defaulting market participants* including any *prudential support* held by the *IESO*, or on behalf of *non-defaulting market participants* pursuant to a *default levy*, the *IESO* shall first repay all existing lines of credit and other banking facilities, including the portion of the *deferred payment plan line of credit* applicable to such *defaulting market participants*, and following repayment of such lines of credit and banking facilities, the *IESO* shall then repay on a pro-rata basis all *real-time market creditors* owed amounts pursuant to section 6.14.7.

PART 5 – IESO BOARD DECISION RATIONALE

Insert Text Here

Appendix "B" – Smart Metering Charge Rule Amendment – Question and Answers (October 2007)

The most efficient and cost-effective way to levy the Smart Meter Charge (SMC) is to incorporate it into the existing IESO settlement, invoicing and payments process. The current market rule amendment, MR-00336-R00-R01, in front of the Technical Panel will allow the IESO and local distribution companies (LDCs) to use existing settlement and invoicing processes.

Below are IESO responses to questions raised by Technical Panel members about MR-00336. These questions are grouped under six main categories:

- market participant default;
- cross-subsidization;
- amendment clarifications;
- rate information;
- SME governance and operation; and
- other questions

Market Participant Default

Q1: What would happen if a market participant LDC makes a partial payment of an invoice that has both wholesale market charges and an SMC?

A1: If a market participant LDC makes a partial payment, and the LDC does not indicate how the payment should be allocated, the IESO will first allocate the partial payment to the wholesale market charges and then any remaining payment amount to the SMC. This ensures that the market participant LDC has the right to allocate funds to any outstanding debts it chooses, as would the case if the IESO issued a separate invoice for the SMC.

If the partial payment does not cover all wholesale market charges, the IESO would treat that as an event of default under the market rules. If the partial payment does cover all wholesale market charges, but not the SMC, the IESO would treat that situation as permitted under the SME framework. The SME framework does not provide for the equivalent of the "default levy." In the event the monies were never recovered, the IESO intends to fund the shortfall using the SME deferral account which would be recovered within the calculation of future SMC rates.

Cross Subsidization

Q2: Is there a risk of cross-subsidization between IESO's SME activities and the IESO's role as the market and systems operator?

A2: **The purpose of the SMC is to recover costs directly associated with the IESOs role as the SME. The SMC is separate and distinct from the IESO administration charge and all costs associated with the SMC including staffing will be accounted for in the SMC.**

The issue of cross-subsidization is within the purview of the OEB and its associated proceedings.

Q3: How will the IESO keep the functions of the IESO and the wholesale market separate from its SME responsibilities? Shouldn't the IESO keep these two functions as separate as possible?

A3: **The IESO will take steps to ensure that costs related to the fulfillment of its SME responsibilities will be separately accounted for. This would include accounting for the activities of staff dedicated to the SME role and any other instance involving the usage of staff time or resources from elsewhere within the IESO organization.**

Q4: Is it appropriate for the IESO to use wholesale market systems and processes for collection of charges that are outside of the wholesale market?

A4: **Yes, the use of existing systems and processes will ultimately reduce costs to the end-use consumer as it will avoid the need for the IESO and the LDCs to develop new processes for reconciliation, invoicing, payment and notices of disagreement. In addition, this amendment will allow LDCs that are market participants to make a single payment to deal with all transactions involving the IESO.**

The use of wholesale market systems and processes for other charges is not new. Currently, there are several charges whose structure are not governed by the market rules but are nonetheless administered via IESO systems and processes such as transmission charges, the debt retirement charge and the global adjustment. The IESO administers the collection and distribution of these charges (to MPs and non-MPs) by leveraging its existing processes and wants to use the same approach for the SMC. One significant difference between the proposed treatment of the SMC relative to the existing treatment of charges such as the debt retirement charge is that failure to pay these latter charges is an event of default under the market rules. Failure to pay the SMC is not an event of default under the market rules.

Q5: Is there a possible co-mingling issue by using the same bank account for the wholesale market charges and the SMC?

A5: **No. The IESO will always know the balance of the SMC within the IESO settlement clearing account. This amendment allows the LDC to transact with the same bank account for all transactions with the IESO.**

Q6: Does the IESO accept risks associated with potential future changes to the wholesale market rules that may adversely affect the SME and administration of the SMC?

A6: **The IESO accepts the risks with this rule amendment where future changes to the wholesale market might negatively impact the implementation of the SMC. If such changes do occur, the IESO would review the impacts on the SME and SMC activities and make changes to those activities as appropriate.**

Q7: Is there potential for changes to market rules and processes to accommodate non-market participants paying the smart metering charge?

A7: There is no potential for changes to the market rules and processes to accommodate non-MPs paying the SMC.

<u>Amendment Clarifications</u>

Q8: Has the IESO considered alternatives to the approach set out in MR-00336?

A8: The IESO has not looked at any alternatives extensively. An alternative such as separate invoicing could be done using the existing software and would not cost that much to the IESO. With an alternative approach, the IESO and organizations using the meter data management and repository (MDM/R), would need to develop separate processes for reconciliation, invoicing, payment, notices of disagreement and other processes.

Q9: Is the IESO imposing and exposing market rules and processes on entities that are not market participants?

A9: The IESO does not have the authority under the Electricity Act, 1998 to require embedded LDCs to register as market participants and adhere to the market rules. Rather, each LDC that participates in the MDM/R will be contractually bound by the SME-LDC agreement to use the IESO's settlement and dispute resolution processes. The relevant market rules will be incorporated into the SME-LDC agreement that all LDCs will be require to sign before participating in the MDM/R. The agreement between the IESO, as SME, and the participating LDCs must be approved by OEB.

Q10: If this market rule amendment is passed and, in the future, the IESO is no longer the SME, could the same processes be used?

A10: Yes, as long as the regulatory framework surrounding the new SME would allow it.

Q11: If the amendment fails, could the IESO still use the settlement clearing account?

A11: No. The market rules define the uses of the settlement clearing account. Unless the market rules are amended to make an exception for the SMC, the settlement clearing account cannot be used.

Q12: Does placing the smart metering charge on a market participant's invoice provide an obligation for the participant to pay it?

A12: The obligation to pay the SMC is formed by the SME-LDC agreement, and not the market rules, even in cases where the LDC is also a market participant. The IESO does not consider the SMC to be a charge under the market rules. Accordingly, the SMC will not be a factor when calculating a market participant's prudential support obligation and failing to pay the SMC will not constitute an event of default under the market rules.

Q13: Why is the rule amendment necessary? Can't the SME-LDC agreement specify the use of the account?

A13: The rule amendment is necessary to use the settlement clearing account. As noted above, the market rules govern the usage of the settlement clearing account.

Q14: What will this proposal cost embedded LDCs that are not currently market participants?

A14: The only potential cost would be for an LDC to set up Electronic Funds Transfer capability with its bank so that it can remit the SMC to the IESO. The LDC will also need to get access to the IESO reports site, where it will be able to retrieve its settlement statement and invoice, but there is no associated cost. It is up to the individual non-MP to decide the extent to which they utilize the settlement statement for reconciliation purposes

Smart Metering Charge Rate

Q15: Has the IESO applied for the SMC rate order from the OEB and what body has jurisdiction over the rate order?

A15: The IESO has not yet applied for the rate order. Currently, the IESO does not know whether the Ministry of Energy or OEB will formulate the initial rate structure, but the OEB will have long term authority over it.

Q16: Who will monitor compliance of the SMC?

A16: Compliance related to the smart metering initiative relates to adherence to the SME-LDC agreement including non-payment of the SMC. The role of compliance is different with the SME than it is in the wholesale market. SME staff and the MDM/R operational service provider will monitor interactions between the MDM/R and the MDM/R service recipient (LDC, retailer, agent, etc).

Q17: Will LDCs pass on the SMC to end-use consumers?

A17: The method of cost recovery will be decided by the OEB.

Q18: What is the rate structure of the SMC?

A18: This has not yet been determined. See answer to the rate application question (Q15) above.

Q19: Shouldn't the payment of the smart metering charge, a non-wholesale market charge, be on a more commercial basis of invoicing (e.g. payment within 30 days instead of 2 business days)?

A19: The IESO appreciates that LDCs are concerned about being open to short payments on the SMC from their end-user customers. The IESO is not opposed to invoicing the SMC based on the previous month's activity (rather than the billing period to which the invoice pertains (as is the case with most other settlement amounts) if the OEB's rate order will allow for this practice.

Q20: Will the SMC cover all the smart metering costs?

A20: No. The SMC will cover the IESO's costs in procuring and administering the MDM/R, but will not include any costs incurred by individual LDCs to access the MDM/R. The precise scope of the SMC is subject to regulation by the Ministry of Energy and/or the OEB.

SME Governance and Operation

Q21: Would the use of the IESO's settlement system make it more difficult to transfer the SME function to a different entity in the future?

A21: Assignment of the SME function is the prerogative of the Minister of Energy. Given that the bulk of the IESO's SME functions are fulfilled through an agreement with an external Operational Service Provider, this role could be easily transferred to another entity. In the event of a transfer, the use of the IESO's settlement systems could be unwound through amendments to the SME-LDC agreement.

Q22: Does the IESO have the authority to be the SME?

A22: The IESO was named as the Smart Metering Entity by Ontario Regulation 393/07 made under the Electricity Act, 1998. The appointment of the IESO is consistent with the IESO's statutory objects to "plan, manage and implement" and to "oversee, administer and deliver" the smart metering initiative or any aspect of the initiative (see Ontario Regulation 452-06).

Q23: Does the OEB's Affiliate Relationship Code (ARC) apply to the SME and the IESO?

A23: The ARC applies to licensed transmitters and distributors in Ontario and requires the separation of a monopoly function (e.g. distribution wires business) from a competitive function (e.g. retail marketer) within the same organization. The ARC does not apply to the provision of MDM/R services by the SME. Further, as a non-profit corporation whose activities are constrained by the objects set out in the Electricity Act, 1998, the IESO could not use any customer information obtained from an LDC through the MDM/R to engage in a business that competes with the LDC. In any event, the IESO will not require LDCs to store data that would identify its customers (such as names, addresses, etc.) in the MDM/R,

Other Questions

Q24: Will the MDM/R provide reports for the reconciliation of the SMC?

A24: Reports from both the MDM/R and settlement statements will provide data that will allow for reconciliation of the SMC. The nature of the data provided from the MDM/R is contingent on the structure of the SMC.

Q25: Are there implications for a host LDC?

A25: **No. Both directly connected and embedded LDCs will be required to sign the SME-LDC agreement, and the SMC charge will be invoiced to all signatories of the agreement. The host will not be held liable for any shortfalls for their embedded LDCs.**

Q26: Could the IESO issue manual invoices for the SMC?

A26: **Yes, but that would eliminate the efficiency gains made by using existing IESO processes for settlements, notice of disagreements, etc. By using the existing framework, existing MPs would reconcile the SMC in the same way as other charges.**

Q27: What is the timeline for implementation of the SMC? Is the timeline dependent on the installation of the smart meters?

A27: **A timeline for the implementation of the SMC has not yet been established. As stated above, the rate structure for the SMC will be set by the Ministry of Energy or the OEB and the IESO will implement the SMC in accordance with those directions. The enrollment of an LDC's mart meters in the MDM/R will not be gated by when the LDC's have all their smart meters installed. The plan is to enroll most, if not all, LDCs with only a subset of their planned full compliment of smart meters. Subsequently installed smart meters would be added to the MDM/R incrementally via a routine process.**

B

SMART METERING AGREEMENT FOR DISTRIBUTORS

THIS AGREEMENT dated this • day of •, 20•.

BETWEEN :

[INSERT DISTRIBUTOR NAME], a distributor licensed by the Ontario Energy Board under the *Ontario Energy Board Act, 1998* (Ontario)

(the "**Distributor**")

and

[INSERT NAME OF ORGANIZATION DESIGNATED AS THE SMART METERING ENTITY], designated as the Smart Metering Entity under the *Electricity Act, 1998* (Ontario)

(the "**SME**")

WHEREAS:

A. The **[INSERT NAME]** has been designated as the Smart Metering Entity under the *Electricity Act, 1998* (Ontario) for the purpose of co-ordinating the implementation of the Government of Ontario's Smart Metering Initiative, a key component of which is the MDM/R.

B. The functions required for the MDM/R were established by the Ministry of Energy and set out in the "Meter Data Management and Repository, Functional Specification, Issue 2.0, November 29, 2006".

C. The MDM/R will be utilized to collect, manage, store and retrieve information related to consumers' use of electricity in Ontario and the SME will, subject to any requirements prescribed by regulation and the protection of privacy, provide and promote non-discriminatory access to that information.

D. Pursuant to the procurement process managed by the Independent Electricity System Operator, IBM Canada Limited was engaged on December 5, 2006, as an Operational Service Provider for the design, engineering, delivery, installation, configuration, integration, implementation and operation of the MDM/R.

E. The MDM/R Agreement between the SME and IBM Canada Limited establishes the service levels and certain other terms and conditions under which MDM/R services are provided to distributors.

F. The OEB's Distribution System Code provides that a distributor shall, upon being requested to do so, enter into an agreement with the SME, in a form approved by the OEB, which sets out the respective roles and responsibilities of the distributor and the SME in relation to smart metering and the information required to be exchanged to allow for the conduct of their respective roles and responsibilities.

G. The roles and responsibilities of the SME and the Distributor set out under this Agreement reflect the regulatory framework under which the Smart Metering Initiative is being implemented, including the role of the SME in administering the provision of services to distributors pursuant to all MDM/R Agreements.

NOW THEREFORE, in consideration of the mutual covenants set forth herein and of other good and valuable consideration, the receipt and adequacy of which is hereby acknowledged, the Parties agree as follows:

ARTICLE 1

INTERPRETATION

1.1 Definitions: In this Agreement, the following terms and expressions shall have the meanings set out below unless the context otherwise requires:

1.1.1 **"Agreement"** means this Agreement, including the Schedules to this Agreement.

1.1.2 **"AMI"** means the Distributor's advanced metering infrastructure, including the smart meter, Advanced Metering Communication Device (AMCD), Local Area Network (LAN), Advanced Metering Regional Collector (AMRC), Advanced Metering Control Computer (AMCC), Wide Area Network (WAN), and related hardware, software, and connectivity required for a fully functioning data collection system.

1.1.3 **"Authorized Agent"** has the meaning ascribed to it in section 2.7.

1.1.4 **"Billing Quantity Data"** means smart metering data that is ready for use in billing consumers for their consumption or use of electricity based on the time of day when the electricity was consumed or used;

1.1.5 **"Distributor"** has the meaning ascribed to it above and includes the Distributor's directors, officers, employees, contractors, agents, advisors and consultants.

1.1.6 "**Market Rules**" means the Market Rules for the Ontario Electricity Market.

1.1.7 **"MDM/R"** means the Meter Data Management and Repository developed by the SME within which Smart Metering Data is processed to produce Billing Quantity Data and such data is stored for future use.

1.1.8 **"MDM/R Agreements"** means the Meter Data Management and Repository Development, Hosting and Support Agreement dated December 5, 2006 between the SME and IBM Canada Limited, and all other agreements between the SME and an Operational Service Provider.

1.1.9 **"OEB"** means the Ontario Energy Board or its successor.

1.1.10 **"Operational Service Provider"** means IBM Canada Limited and any other party engaged by the SME, excluding the Independent Electricity System Operator, to assist with the development and operation of the MDM/R.

1.1.11 **"Party"** means a party to this Agreement.

1.1.12 **"Smart Metering Charge"** means any fee payable to the SME in respect of its role and responsibilities in respect of the Smart Metering Initiative and approved by the OEB or otherwise required by law.

1.1.13 **"Smart Metering Data"** means data derived from smart meters, including data related to the consumers' consumption of electricity.

1.1.14 **"Smart Metering Initiative"** means those policies of the Government of Ontario related to its decision to ensure Ontario electricity consumers are provided, over time, with smart meters.

1.1.15 **"SME"** has the meaning ascribed to it above and includes the SME's directors, officers, employees, contractors, agents, advisors and consultants.

1.1.16 **"SME Steering Committee"** means the forum to represent the interests of the MDM/R service recipients to be established by the SME under section 3.2.

1.1.17 **"Terms of Service"** means the terms and conditions made under section 3.1.

1.1.18 **"VEE"** means those validation, estimating and editing services, as specified by the SME, that are performed on Smart Metering Data to identify and account for missed or inaccurate Smart Metering Data.

1.2 Interpretation: In this Agreement, unless the context otherwise requires:

1.2.1 words importing the singular include the plural and vice versa;

1.2.2 words importing a gender include any gender;

1.2.3 other parts of speech and grammatical forms of a word or phrase defined in this Agreement have a corresponding meaning;

1.2.4 the expression "person" includes a natural person, any company, partnership, trust, joint venture, association, corporation or other private or public body corporate, and any government agency or body politic or collegiate;

1.2.5 a reference to a thing includes a part of that thing;

1.2.6 a reference to an article, section, provision or schedule is to an article, section, provision or schedule of this Agreement;

1.2.7 a reference to any statute, regulation, proclamation, order in council, ordinance, by-law, resolution, rule, order or directive includes all statutes, regulations, proclamations, orders in council, ordinances, by-laws or resolutions, rules, orders or directives varying, consolidating, re-enacting, extending or replacing it and a reference to a statute includes all regulations, proclamations, orders in council, rules and by-laws of a legislative nature issued under that statute;

1.2.8 a reference to a document or provision of a document, including this Agreement and any externally referenced documents, includes an amendment or supplement to, or replacement or novation of, that document or that provision of that document, as well as any exhibit, schedule, appendix or other annexure thereto;

1.2.9 a reference to sections of this Agreement or of any externally referenced documents separated by the word "to" (i.e., "sections 1.1 to 1.4") shall be a reference to the sections inclusively; and

1.2.10 the expression "including" means including without limitation, the expression "includes" means includes without limitation and the expression "included" means included without limitation.

1.3 Headings: The division of this Agreement into articles and sections and the insertion of headings are for convenience of reference only and shall not affect the interpretation of this Agreement, nor shall they be construed as indicating that all of the provisions of this Agreement relating to any particular topic are to be found in any particular article, section, subsection, clause, provision, part or schedule.

ARTICLE 2

ROLES AND RESPONSIBILITIES

2.1 Compliance with Applicable Law: The Parties shall comply with the provisions of all applicable laws and any codes issued by the OEB that relate to the Smart Metering Initiative.

2.2 Roles and Responsibilities of the SME: The SME shall:

2.2.1 administer the ongoing development of the MDM/R and any associated SME infrastructure required to fulfill the Smart Metering Initiative;

2.2.2 co-ordinate with other bodies having regulatory functions with respect to the Smart Metering Initiative, including the OEB and the Ministry of Energy and Infrastructure, as appropriate;

2.2.3 conduct such testing as the SME determines appropriate of the MDM/R and the interfaces between the MDM/R and the Distributor's systems prior to authorizing the Distributor to operate using the MDM/R and in advance of a modification to the MDM/R;

2.2.4 cooperate with reasonable testing by the Distributor of the interfaces between the MDM/R and the Distributor's systems requested by the Distributor, including reasonable testing by the Distributor of the interoperation of the Distributor's systems with the MDM/R;

2.2.5 provide reasonable and effective training to staff of the Distributor and the Distributor's Authorized Agent on the MDM/R and any associated infrastructure provided by the SME to support the interoperation of the Distributor's systems with the MDM/R;

2.2.6 subject to any requirements prescribed by regulation, receive Smart Metering Data, and such other information required by the SME to fulfill its obligations in respect of the Smart Metering Initiative, from the Distributor or the Distributor's Authorized Agent, conduct the applicable VEE processes for such information, and transmit Billing Quantity Data to the Distributor or the Distributor's Authorized Agent in a form that allows the Distributor to bill in accordance with an OEB approved tariff;

2.2.7 provide the Distributor with remote access to the MDM/R on a non-discriminatory basis for the purposes of:

2.2.7.1 retrieving and reviewing the Distributor's Smart Metering Data and Billing Quantity Data for any business purpose of the Distributor; or

2.2.7.2 editing the Distributor's Smart Metering Data and other information the Distributor is authorized to edit;

provided that the SME may establish reasonable restrictions on remote access to safeguard the operational integrity of the MDM/R, ensure performance of the MDM/R in accordance with the applicable service levels prescribed in the Terms of Service, perform maintenance on the MDM/R, or resolve an outage of the MDM/R;

2.2.8 provide ongoing technical support to the Distributor in relation to the MDM/R and any associated SME infrastructure required to fulfill the Smart Metering Initiative;

2.2.9 ensure that Smart Metering Data transmitted to the SME by the Distributor is stored in the MDM/R for 26 months and available to the Distributor for 10 years in an archived format, or as otherwise required by law;

2.2.10 perform its obligations under the Terms of Service and make best efforts to ensure that the MDM/R services meet the applicable service levels prescribed in the Terms of Service;

2.2.11 work with stakeholders to achieve continuous service through any transition to any subsequent agreement or agreements relating to MDM/R operations;

2.2.12 carry out such other roles and responsibilities as are required to fulfill the Smart Metering Initiative.

2.3 **Smart Metering Charge:** The SME shall invoice the Distributor for and collect the Smart Metering Charge in accordance with settlement procedures identical to those set forth in sections 6.1 to 6.15 of Chapter 9 of the Market Rules *mutatis mutandis*. In any application to the OEB to set the Smart Metering Charge, the SME shall request that the OEB permit the Distributor to pass through the Smart Metering Charge to consumers.

2.4 **Audit of the MDM/R:** The SME shall cause independent audits of the MDM/R and the MDM/R internal control environment, including relevant controls performed by the SME and the MDM/R Operational Service Providers, to be conducted annually by a nationally recognized audit firm, the scope and objectives of such audits to be relevant to a user organization's internal control as it relates to an audit of financial statements. The audit shall be conducted in accordance with the standards or equivalent standards to those established by the Canadian Institute of Chartered Accountants for audits of controls at a service organization. The audit period shall be at minimum six months in duration, concluding not more than 3 months from the end of the calendar year. The audit report shall be made available to users of the report no later than November 15 of each calendar year. This report shall hereinafter be referred to as the "first audit report". As early as possible and no later than January 15 of the following calendar year, the SME shall issue a management representation letter from the SME Chief Financial Officer stating that controls continue to be in place and working effectively and that there is no change in the control environment between the date of the audit report and December 31, or, at the SME's option in lieu of the representation letter, a second audit report covering the eight month period up to and including November 30 (hereinafter referred to as the "second audit report").

In the event of any qualification or significant exception in an audit report, at the request of the Distributor and subject to the approval of an officer of the SME or a committee of the SME Board or the SME Board, the SME shall cause to have specified procedures performed by a nationally recognized audit firm. The approval of this request shall not be unreasonably withheld. The Distributor's request shall include the specified procedures requested by their external auditor to be performed by the SME's auditor. Notwithstanding the SME's requirement for approval by an officer of the SME or a committee of the SME Board or the SME Board, the SME shall (a) respond to the Distributor's request in writing within 5 business days of receipt of their request with the specified procedures that the SME shall cause to have performed and (b) advise when the results of the specified procedures will be provided to the Distributor. The SME will use commercially reasonable efforts to have the results of the specified procedures provided to the Distributor within 5 weeks of the approval of the request for specified procedures pertaining to the first audit report and within 2 weeks of the approval of the request for specified procedures pertaining to the second audit report, if applicable, or as otherwise agreed between the Distributor and the SME. The SME may consolidate similar requests from multiple Distributors, provided that such consolidation does not negatively impact on the timing of any of the approvals or the delivery of the results of the specified procedures.

In the event of any qualification or significant exception in the audit report, and where all reasonable means have been exhausted with specified procedures to meet Distributors' financial reporting requirements, Distributors required by law to file audited financial statements with a securities commission and comply with National Instrument 52-109 or equivalent shall have the right to have their financial statement auditor conduct audit procedures of the MDM/R and MDM/R internal control environment, subject to all of the following:

- The scope and objectives of the audit are limited to supporting the audit of and/or certification of Distributor's financial statements;
- Reasonable costs of the audit, including costs of the SME and the MDM/R Operational Service Providers to support the audit, shall be borne by the Distributor; and
- Distributor's external auditor agrees to the SME and MDM/R Operational Service Providers' non-disclosure and information confidentiality terms and conditions.

The SME shall develop and execute a remediation plan to address significant exceptions on a timely basis.

2.5 Interactions with Customers: The Distributor shall be solely responsible for interacting with its customers in respect of individual customer data originating from the MDM/R or any individual customer information derived from the MDM/R regardless of whether such data is presented to the customer by the Distributor, the SME or their respective agents.

2.6 Roles and Responsibilities of the Distributor: The Distributor shall:

2.6.1 ensure that its AMI complies with all of the applicable functional and technical specifications published by the SME with respect to the Smart Metering Initiative and conduct such testing of its AMI as required by the SME to demonstrate such compliance;

2.6.2 participate in any testing of the MDM/R and the interfaces between the MDM/R and the Distributor's systems as required by the SME;

2.6.3 certify to the SME, in a form acceptable to the SME, that the Distributor has completed any testing required by the SME and is ready to operate using the MDM/R, its AMI and any associated infrastructure required to fulfill the Smart Metering Initiative;

2.6.4 transmit to the SME Smart Metering Data and any other information required by the SME under section 2.2.6, retain such information for a minimum of 5 days, and re-transmit such information to the SME upon request;

2.6.5 perform its obligations under the Terms of Service as an MDM/R service recipient; and

2.6.6 carry out such other roles and responsibilities as are required to fulfill the Smart Metering Initiative.

2.7 Authorized Agent Permitted: On written notice to the SME, the Distributor may authorize one or more persons to act on the Distributor's behalf as an agent ("**Authorized Agent**") in any or all of the matters related to the Smart Metering Initiative and this Agreement. The authorization shall be in the form specified by the SME. The Distributor is responsible for ensuring that its Authorized Agent is aware of and complies with the terms and conditions of this Agreement.

ARTICLE 3

TERMS OF SERVICE

3.1 Terms of Service: The SME shall make Terms of Service for the management and operations of the MDM/R under this Agreement and shall publish the Terms of Service on its website.

3.2 SME Steering Committee: The SME shall establish the SME Steering Committee as a forum to represent the interests of stakeholders. The SME Steering Committee shall have up to 13 representatives where:

3.2.1 a majority of the members shall represent local distribution companies that are receiving service from the MDM/R or otherwise eligible to receive service from the MDM/R;

3.2.2 following a date to be established by the SME in consultation with the Ministry of Energy and Infrastructure, up to three members shall represent retail companies that are receiving service from the MDM/R or otherwise eligible to receive service from the MDM/R;

3.2.3 up to two members will be members-at large; and

3.2.4 one member shall represent the interests of the SME.

3.3 Appointment of the SME Steering Committee: Except for the members-at-large and the member representing the SME, members of the SME Steering Committee shall be appointed by the Board of Directors of the *SME* from among nominations made by persons that are receiving service from the MDM/R or otherwise eligible to receive service from the MDM/R. Distributor representatives may also be appointed from nominations submitted by the Board of Directors of the Electricity Distributors Association or any successor organization.

3.4 Amendment to the Terms of Service: The SME may amend the Terms of Service at any time provided that the SME establishes and follows a process by which the SME Steering Committee may first provide advice and recommendations to the SME on the amendment. When amending the Terms of Service, the SME shall consider the overall cost and schedule impacts of the proposed amendment to the SME and any parties receiving service from the MDM/R, and any anticipated impact on electricity consumers.

3.5 Amendment Proposals: The SME shall establish a process under which any party receiving service from the MDM/R may propose an amendment to the Terms of Service.

3.6 Manuals and Procedures: The SME may make and amend manuals and procedures to provide more detailed descriptions of the requirements under the Terms of Service, including any forms required under this Agreement or the Terms of Service, and shall publish any manuals and procedures made under the Terms of Service on its website.

ARTICLE 4

REPRESENTATIONS AND WARRANTIES

4.1 Mutual Representations and Warranties: Each Party represents and warrants to and covenants with the other Party as follows:

4.1.1 it has all the necessary corporate power to enter into and perform its obligations under this Agreement;

4.1.2 the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate and/or governmental action and does not (or would not with the giving of notice, the lapse of time or the happening of any other event or condition) result in a violation or a breach of or a default under or give rise to a right of termination, greater rights or increased costs, amendment or cancellation or the acceleration of any obligation under (i) any charter or by-law instruments of that Party; (ii) any contracts or instruments to which it is a party or by which it is bound; or (iii) any laws applicable to it;

4.1.3 the individual(s) executing this Agreement, and any document in connection with this Agreement, on its behalf has been duly authorized to execute this Agreement and has the full power and authority to bind the Party;

4.1.4 this Agreement constitutes a legal and binding obligation of the Party, enforceable against the Party in accordance with its terms; and

4.1.5 it holds all permits, licences and other authorizations that may be necessary to enable it to carry on the business and perform its roles and responsibilities under the Smart Metering Initiative and this Agreement.

4.2 Representations and Warranties of the SME: The SME represents and warrants to the Distributor that it and any Operational Service Provider have adequate qualified employees and other personnel and organizational and other arrangements that are sufficient to enable it to perform all of its roles and responsibilities under the Smart Metering Initiative and this Agreement.

4.3 Representations and Warranties of the Distributor: The Distributor represents and warrants to the SME that:

4.3.1 the Distributor is a **[INSERT FORM OF BUSINESS ORGANIZATION]** duly **[INCORPORATED/ FORMED/REGISTERED]** and existing under the laws of **[JURISDICTION]**;

4.3.2 the Distributor and any Authorized Agent has the authority under any applicable laws to provide Smart Metering Data and any other information required under section 2.2.6 to the SME; and

4.3.3 the Distributor or its Authorized Agent have adequate qualified employees and other personnel and organizational and other arrangements that are sufficient to enable it to perform all of its roles and responsibilities under the Smart Metering Initiative and this Agreement.

ARTICLE 5

ACCESS TO MDM/R DATA

5.1 Disclosure of MDM/R Data: Subject to its OEB licence, the SME may disclose, use or reproduce any data contained in the MDM/R, including Smart Metering Data and Billing Quantity Data, for any purpose; provided that in making data available to any third party, the data shall be presented in a manner that prevents the specific data of an individual customer of the Distributor being identified with that customer or premises. If the SME is compelled by law, regulation or order of court or tribunal to disclose any data contained in the MDM/R to a third party in a manner other than as provided for under this section 5.1, the SME shall, to the extent permitted by law, provide the Distributor with reasonable notice and the Distributor may seek a protective order or other appropriate remedy to prevent disclosure of the data.

5.2 Protocol for Access to MDM/R Data: The SME shall consult with the SME Steering Committee and develop and publish a protocol setting out the procedures it will follow in providing access to MDM/R data while preventing identification of the specific data associated with an individual customer or premises.

5.3 Freedom of Information and Protection of Privacy Act: The Distributor acknowledges that SME is bound by the provisions of the *Freedom of Information and Protection of Privacy Act* (Ontario) and may be required by order of a court or tribunal to disclose information provided by the Distributor to SME. The SME acknowledges that the Distributor may be bound by the provisions of the *Freedom of Information and Protection of Privacy Act* (Ontario), the *Municipal Freedom of Information and Protection of Privacy Act* (Ontario) or other such legislation and may be required by order of a court or tribunal to disclose information provided by the SME to the Distributor.

ARTICLE 6

INTELLECTUAL PROPERTY

6.1 Intellectual Property Rights: The Distributor shall not acquire any title, beneficial ownership interests or any intellectual property rights, including any proprietary rights provided under (i) patent law, (ii) copyright law (including moral rights), (iii) trade-mark law, (iv) design patent or industrial design law, (v) semi-conductor chip, integrated circuit topography or mask work law, or (vi) any other statutory provision or common law principle regarding intellectual or industrial property, including trade secret law, in the MDM/R or any associated infrastructure used by the SME to fulfill the Smart Metering Initiative. Similarly, the SME shall not acquire any such title, interests or rights in respect of the Distributor's AMI, customer information systems, billing systems or any associated infrastructure used by the Distributor to fulfill those objectives.

6.2 Survival: Article 6 of this Agreement shall survive the assignment, transfer or termination of this Agreement.

ARTICLE 7

LIABILITY AND INDEMNIFICATION

7.1 **Limitation of Liability of the SME**: Except as provided in sections 7.5, 7.6 and 7.7, the Distributor shall have no recourse against the SME in respect of any breach of this Agreement, or any loss or damage to the Distributor, which in either case is attributable to an act or omission of any Operational Service Provider. The SME's liability to the Distributor attributable to an act or omission of the SME shall be limited to:

7.1.1 actual direct damages and in no event shall the SME be liable to the Distributor in respect of punitive, consequential or indirect damages or loss of profit, loss of data or loss of revenue; and

7.1.2 the cumulative liability of the SME to all MDM/R service recipients (including the Distributor) in connection with an act or omission of the SME under this Agreement shall not exceed an aggregate amount of $1,000;

except as provided for in section 7.3 or to the extent that any such damages are recovered by the SME from an Operational Service Provider under section 7.6.

7.2 **Limitation of Liability of the Distributor:** The Distributor's liability to the SME attributable to an act or omission of the Distributor shall be limited to actual direct damages and in no event shall the Distributor be liable to the SME in respect of punitive, consequential or indirect damages or loss of profit, loss of data or loss of revenue. The liability of the Distributor to the SME in connection with an act or omission of the Distributor shall not exceed $1,000.

7.3 **Indemnification:** The SME shall indemnify and hold harmless the Distributor from any and all claims, losses, liabilities, obligations, actions, judgments, suits, costs, expenses, disbursements and damages incurred, suffered, sustained or required to be paid, directly or indirectly, by, or sought to be imposed upon, the Distributor to the extent that such claims, losses, liabilities, actions, judgments, suits, costs, expenses, disbursements or damages arise out of a breach of Article 5 of this Agreement.

7.4 **Duty to Mitigate:** A Party has a duty to mitigate damages, losses, liabilities, expenses or costs relating to any claims that may be made under this Agreement.

7.5 **Cost Recovery:** The SME shall cooperate with the Distributor (acting individually or in concert with other licenced distributors that are parties to an agreement with the SME) in:

7.5.1 any proceeding before the OEB; and

7.5.2 any initiative to make a submission to, or obtain a legislative or regulatory amendment from, the Province of Ontario;

in which the Distributor seeks a change to any of its rates or charges or other appropriate relief for any of its losses or incremental costs related to any act or omission of the SME, the Operational Service Provider or a service provider of the SME. The SME shall assist in the coordination of the claim or initiative being put forward by the Distributor. Such cooperation by the SME shall include, but not be limited to, promptly providing to the Distributor and the OEB, at the request of the Distributor but at the SME's cost, accurate information, analysis, documents, and evidence. For greater certainty, the SME's obligation to provide assistance under this section shall not be limited to a cost of $1000 by section 7.1.2.

7.6 **Reduction of Smart Metering Charge:** If an Operational Service Provider fails to meet the required service levels under an MDM/R Agreement, or otherwise breaches an MDM/R Agreement, and that failure or breach results in a reduction of the fees payable to the Operational Service Provider by the SME, or if any amount is recovered from the Operational Service Provider in respect of any such failure or breach, then an amount equal to the reduction or recovered amount will be:

7.6.1 set aside by the SME as an amount owing to MDM/R service recipients;

7.6.2 reported to the SME Steering Committee along with any pertinent information in the possession of the SME which may assist the SME Steering Committee in determining which MDM/R service recipients were affected by the MDM/R failure or breach; and,

7.6.3 subsequently distributed to MDM/R service recipients by the SME in the manner directed by SME Steering Committee.

The SME Steering Committee shall allocate such funds using any methodology it considers appropriate and resolve any disputes between the Distributor and any other MDM/R service recipient with respect to the allocation of such funds. The Distributor and the SME agree to adhere to all decisions made by the SME Steering Committee with respect to the allocation of such funds.

7.7 Monitoring of the Operational Service Provider: The SME will use commercially reasonable efforts to monitor each Operational Service Provider's performance under, and to enforce the provisions of, its MDM/R Agreement (which shall include, for greater certainty, the diligent pursuit, through legal proceedings if necessary, of any appropriate reductions of fees or recovery of any amounts owing as damages, penalties or otherwise). The Distributor may seek an order of specific performance requiring the SME to take commercially reasonable actions to enforce the provisions of an MDM/R Agreement at the SME's cost.

ARTICLE 8

DISPUTE RESOLUTION

8.1 Dispute Resolution: Subject to section 8.3, the Parties shall attempt to settle any dispute in connection with this Agreement or the Smart Metering Initiative through good faith negotiations. If the Parties are unable to resolve the dispute through good faith negotiation, either Party may apply to the OEB for determination of the dispute. A Party shall provide written notice to the other Party of its intention to apply to the OEB for determination of the dispute at least ten (10) business days before filing any application materials with the OEB.

8.2 Limitation Period: Subject to section 8.3, a Party shall commence any proceeding in respect of a dispute under this Agreement or related to the Smart Metering Initiative within two years of the earlier of:

8.2.1 the date on which the claim is discovered; or

8.2.2 the date on which this Agreement is terminated under section 11.1.

8.3 Smart Metering Charge: Any dispute between the Parties in respect of the calculation of the Smart Metering Charge shall be determined in accordance with a dispute resolution procedure identical to that set forth in section 2 of Chapter 3 of the Market Rules *mutatis mutandis*. The Distributor shall commence any proceeding in respect of the calculation of the Smart Metering Charge invoiced to it by the SME within the applicable limitation period set forth in section 2.5.1A.3 or 2.5.1A.4 of Chapter 3 of the Market Rules.

ARTICLE 9

FORCE MAJEURE

9.1 Force Majeure: If either Party is unable to satisfy any of its obligations under this Agreement due to causes beyond the Party's reasonable control, provided that the Party makes all reasonable efforts to avoid, or if unavoidable, to correct the reason for such delay or failure and gives the other Party prompt notice of such delay or failure, then such Party shall be excused and relieved from its obligation to satisfy such obligation for so long as the event continues and for such reasonable period of time thereafter as may be necessary for the Party to resume performance of the obligation. For the avoidance of doubt, "causes beyond the Party's reasonable control" include an event of fire, flood, earthquake, element of nature, explosions, acts of God, acts of war, terrorism, riots, civil or public disorders or disobedience, strikes, lock-outs, labour disruptions, acts of vandalism, sabotage, or other unlawful acts, and any other similar event beyond the commercially reasonable control of the Party.

ARTICLE 10

AMENDMENT AND ASSIGNMENT

10.1 Amendment Generally: Except as otherwise provided in this Agreement, no amendment to this Agreement will be effective until approved by the OEB. A Party may apply to the OEB to amend this Agreement at any time provided that the Party has first consulted with the SME Steering Committee on the merits of the proposed amendment.

10.2 Amendment to Section 4.3: The Distributor may amend the Distributor's corporate information provided under section 4.3 at any time without the approval of the OEB.

10.3 Amendment to Schedule "A": The Distributor or the SME may amend their respective nominated representatives for official notifications listed in Schedule "A" at any time without the approval of the OEB.

10.4 Assignment Generally: Except as provided for in section 11.2, neither Party may assign its rights and obligations under or transfer any of its interest in this Agreement without the prior consent of the other Party, which consent shall not be unreasonably withheld. An assignment under this section does not require the approval of the OEB.

ARTICLE 11

TERM AND TERMINATION

11.1 Term: Unless otherwise extended by order of the OEB, this Agreement shall terminate on March 31, 2012.

11.2 Termination of the Smart Metering Entity Role: If during the term of this Agreement, the SME is no longer designated under the *Electricity Act, 1998* (Ontario) as the Smart Metering Entity, this Agreement shall be assigned to and assumed by the successor Smart Metering Entity.

11.3 Delivery of Historical Data: In the event that MDM/R services are no longer being provided under either this Agreement or any subsequent agreement or agreements relating to MDM/R operations, the SME shall, at the request of the Distributor, obtain and deliver to the Distributor the Distributor's Smart Metering Data and Billing Quantity Data stored in the MDM/R. This section 11.3 shall survive the assignment, transfer or termination of this Agreement.

11.4 Deemed Release of the SME: Subject to section 6.2, the Distributor will be deemed to release the SME from all obligations, liabilities, claims and demands against SME in respect of the Smart Metering Initiative and this Agreement, whether known or unknown, upon the earlier of:

11.4.1 two years after termination of this Agreement; or

11.4.2 the assumption of any obligations, liabilities, claims and demands against SME in respect of the Smart Metering Initiative and this Agreement by another entity in accordance with section 11.2.

ARTICLE 12

MISCELLANEOUS

12.1 No Agency or Partnership: The Parties do not intend that any agency or partnership be created between them by this Agreement.

12.2 No Warranty: Except as specifically set forth in this Agreement, there are no representations, warranties, or conditions of either Party, express, implied, statutory or otherwise, regarding any matter, including warranties or conditions of merchantable quality or fitness for a particular purpose.

12.3 Successors and Assigns: This Agreement shall enure to the benefit of, and be binding on, the Parties and their respective successors and permitted assigns.

12.4 Severability: Any provision of this Agreement that is invalid or unenforceable shall be ineffective to the extent of that invalidity or unenforceability and shall be deemed severed from the remainder of this Agreement, all without affecting the validity or enforceability of the remaining provisions of this Agreement or affecting the validity or enforceability of such provision in any other jurisdiction.

12.5 Notices: Any notice or other communication required or permitted to be given or made under this Agreement shall be sent by courier or other form of personal delivery, by prepaid first class mail, by facsimile or electronic mail and be addressed to the other Party in accordance with the contact information listed in Schedule "A" of this Agreement.

12.6 Governing Law: This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein. The Parties irrevocably attorn to the exclusive jurisdiction of the courts of the Province of Ontario.

12.7 Conflict or Inconsistency: In the event of a conflict or inconsistency between this Agreement and the provisions of the Terms of Service, this Agreement shall prevail. In the event of a conflict or inconsistency between this Agreement and any code issued by the OEB under section 70.1 of the *Ontario Energy Board Act* (Ontario), the code shall prevail.

12.8 Amendment to the Market Rules: If the SME proposes to or receives a proposal to amend any provision of the Market Rules incorporated in this Agreement by reference, the SME shall provide the Distributor with reasonable notice of the proposed amendment and identify what impact the amendment will have upon this Agreement.

12.9 Waiver: No failure or delay by a Party in exercising any right, power or privilege under this Agreement shall operate as a waiver thereof. No provision of this Agreement may be waived except in writing by a Party at its sole discretion, and a waiver on any occasion shall not act as a waiver or bar to the enforcement of the rights of a Party with respect to any other breach or the same breach on any other occasion.

12.10 Entire Agreement: This Agreement represents the complete agreement between the Parties and supersedes all prior communications, understandings and agreements between the Parties, whether written, oral, expressed or implied.

12.11 Counterparts: This Agreement may be executed by the Parties by facsimile or electronic signature and in separate counterparts, each of which when so executed and delivered will be an original, but all such counterparts will together constitute one and the same instrument.

IN WITNESS WHEREOF the Parties have, by their duly appointed and authorized representatives, executed this Agreement.

[INSERT DISTRIBUTOR NAME]

By: ______________________________________

Name:
Title:

[INSERT NAME OF SMART METERING ENTITY]

By: ______________________________________

Name:
Title:

SCHEDULE "A"

NOMINATED REPRESENTATIVES FOR OFFICIAL NOTIFICATIONS

SME

Name of SME Representative:	
Title:	
Address:	
City/Province/Postal Code	
Email address:	
Phone:	
Fax:	

Distributor

Name of Distributor Representative:	
Title:	
Address:	
City/Province/Postal Code	
Email address:	
Phone:	
Fax:	

C

SME_AGR_0002

Meter Data Management and Repository

Terms of Service

ieso

Power to Ontario.
On Demand.

Issue 1.0 , February 23, 2010

Library Record No.	SME_AGR_0002
Document Name	MDM/R Terms of Service
Issue	Issue 1.0
Reason for Issue	
Effective Date	February 23, 2010

Table of Contents

1. MDM/R Governance

1.1 Contractual Force

1.1.1 The *terms of service* are given contractual force and effect as between each *MDM/R service recipient* and the *SME* by virtue of the execution of the *smart metering agreement* under which each *MDM/R service recipient* and the *SME* agreed to perform its respective obligations under the *terms of service*.

1.1.2 The *terms of service* set out the principles regarding the administration and operational framework of the *MDM/R* and any other infrastructure required to fulfill the obligations set out in the *smart metering agreement* between the *SME* and an *MDM/R service recipient.*

1.2 SME Steering Committee

1.2.1 The *SME* shall establish the *SME steering committee* as a forum to represent the interests of the *MDM/R service recipients*. The *SME steering committee* will be provided with an opportunity to:

- provide input in the ongoing development of the *terms of service* and the *MDM/R manuals and procedures*;
- provide input on the *SME's* provision of *MDM/R* services and the adherence to the committed service levels as prescribed in the *terms of service*;
- consider *amendment proposals* forwarded by the *SME, MDM/R service recipients*, or initiated by the *SME steering committee*; and
- participate in the consultations, when requested by the *SME*, on amendments to the *MDM/R manuals and procedures.*

1.2.2 The *SME* may request members of the *SME steering committee* to provide feedback on particular topics and/or respond to various surveys from time to time.

1.2.3 The composition of the *SME steering committee* shall be as set out in the *smart metering agreement.*

1.2.4 Except for the members-at-large and the member representing the *SME*, members of the *SME steering committee* shall be appointed by the Board of Directors of the *SME* from among nominations made by *MDM/R service recipients* or entities eligible to become *MDM/R service recipients*. Distributor representatives may also be appointed from nominations submitted by the Board of Directors of the Electricity Distributors Association or any successor organization.

1.2.5 The Board of Directors of the *SME* may solicit nominations to encourage a broad selection of qualified candidates for the various representative and at-large positions. Expertise in MDM/R, AMI and *CIS* technologies and associated business processes will be a factor in making appointments.

1.2.6 Subject to section 1.2.7, members of the *SME steering committee* shall serve for a term of two years.

1.2.7 The Board of Directors of the *SME* may appoint members of the *SME steering committee* for a term of one year to ensure regular rotation of membership of the *SME steering committee.*

1.2.8 When selecting members to represent distributors, the Board of Directors of the *SME* may consider such factors as providing representation from a range of *AMI* and *CIS* technologies as well as a range of utility size, geographic location, and demographics.

1.2.9 The following persons are disqualified from being a member of the *SME steering committee*:

- a person who is less than eighteen years of age;
- a person who is of unsound mind and has been so found by a court in Canada or elsewhere;
- a person who is not an individual;
- a person who has the status of bankrupt; or
- a person who is an employee of or has a material interest in any company or organization providing goods or services to the *SME* while acting in its capacity as the *SME*.

1.2.10 In the event that a member's position on the *SME steering committee* becomes vacant prior to the end of the member's term, the Board of Directors of the *SME* may appoint a new member in accordance with the procedure outlined in section 1.2.4 to fill the position for the remainder of that term.

1.2.11 A majority of the members of the *SME steering committee* shall be considered a quorum.

1.2.12 The *SME steering committee* may establish its own procedures, including provisions relating to:

- the frequency, format, location and scheduling of meetings;
- attendance requirements for members of the *SME steering committee*;
- procedures that govern the conduct of meetings;
- method of selecting a Chair of the *SME steering committee*, who shall not be the *SME* member; and
- any administrative matters that are not otherwise stipulated by the *terms of service.*

1.2.13 The *SME steering committee* may recommend that the *SME* form working groups or standing committees to consider topics in specific areas.

1.2.14 Material submitted to or discussed at meetings of the *SME steering committee* will not normally be confidential. If confidential material is necessary for the consideration of a matter, the *SME steering committee* will establish appropriate confidentiality safeguards prior to receipt of that material.

1.3 Amending the Terms of Service

1.3.1 An *MDM/R service recipient* or any other interested person may propose an amendment to the *terms of service* and shall file with the *SME* an amendment submission in a form specified by the *SME* and a statement of the reason for which such amendment may be necessary or desirable. The *SME* shall publish the amendment submission and the accompanying statement.

1.3.2 The *SME* may at any time propose on its own initiative to amend the *terms of service* as may be necessary or desirable. The *SME* shall publish an amendment submission in a form specified by the *SME* and a statement of the reason for which such amendment may be necessary or desirable.

1.3.3 Any *amendment proposal* to the *terms of service* from the *SME* or other parties shall be referred to the *SME steering committee* for consideration unless the *SME* determines that the amendment is an *urgent amendment*, in which case, the *SME* shall file a statement with the *SME steering committee* indicating that, in its opinion, an amendment to the *terms of service* is urgently required for one or more of the following reasons:

- To avoid, reduce the risk of or mitigate the effects of conditions that affect the ability of the *MDM/R* to function within defined service levels.
- To avoid, reduce the risk of or mitigate the effects of the abuse of MDM/R services by an *MDM/R service recipient* or any other party.
- To implement regulations or other any applicable law which requires immediate compliance by the *SME* or an *MDM/R service recipient*.
- To avoid, reduce the risk of or mitigate the effects of an unintended adverse effect of a provision or provisions in the *terms of service*

1.3.4 The *SME steering committee* shall report to the *SME* its recommendation on each *amendment proposal* in a form specified by the *SME*. The *SME steering committee's* report shall include its recommendation on the *amendment proposal* and highlight any further additions, deletions or changes to the original *amendment proposal* recommended by the *SME steering committee* and the reasons for each recommended change.

1.3.5 In its report to the *SME*, the *SME steering committee* shall recommend a schedule for the implementation of an amendment to permit *MDM/R service recipients* a reasonable time to modify their systems and procedures to accommodate the change.

1.3.6 The *SME* shall consider any recommendations received from the *SME steering committee* but is not be obligated to accept the recommendations when approving or rejecting the *amendment proposal* and shall publish its decision and provide a statement of the reason for any additions, deletions or changes to the *amendment proposal*.

1.3.7 The *SME* may approve or reject any *amendment proposal* and make any additions, deletions or changes to the *amendment proposal* that it deems necessary. The *SME* shall publish its decision and provide a statement of the reason for any additions, deletions or changes to the *amendment proposal*.

1.3.8 The *SME* shall implement any amendment to the *terms of service* in accordance with section 2.5 of the *terms of service*.

1.3.9 If in the judgment of the SME, an amendment to the *terms of service* would require a material increase in the *smart metering charge*, the SME may delay implementation of the amendment until a corresponding increase in the *smart metering charge* is approved by the OEB.

1.4 MDM/R Manuals and Procedures

1.4.1 The *SME* may create *MDM/R manuals and procedures* to provide further detail on the implementation of the *terms of service* and shall *publish* any *MDM/R manuals and procedures*. The *MDM/R manuals and procedures* will address three main categories of activities:

- registration and enrolment with the *MDM/R*;
- steady state operations of the *MDM/R*; and
- managing changes.

1.4.2 An *MDM/R service recipient* or any other interested person may propose an amendment to the *MDM/R manuals and procedures* and shall file with the *SME* an amendment submission in a form specified by the *SME* and a statement of the reason for which such amendment may be necessary or desirable. The *SME* shall publish the amendment submission and the accompanying statement.

1.4.3 The *SME* may at any time determine on its own initiative or amend the *MDM/R manuals and procedures* as may be necessary or desirable. The *SME* shall publish an amendment submission in a form specified by the *SME* and a statement of the reason for which such amendment may be necessary or desirable.

1.4.4 The *SME* shall establish a process for reviewing and considering *amendment proposals* to *MDM/R manuals and procedures*. Other than in the case of *urgent amendments,* the *SME* shall engage *MDM/R service recipients* in the development of amendments to the *MDM/R manuals and procedures*. Changes to forms and other supporting documentation referenced within the procedure will not be subject to a stakeholder process.

1.4.5 The *SME* may approve or reject *amendment proposals* to the *MDM/R manuals and procedures*. The *SME* shall report its decisions on such matters to *MDM/R service recipients* giving its reasons for the decision, including any further changes made to the *amendment proposal* by the *SME.*

1.4.6 The *SME* shall implement any amendment to *MDM/R manuals and procedures* in accordance with section 2.5 of the *terms of service*.

1.5 Urgent Amendments

1.5.1 In urgent situations meeting one or more of the criteria set out in section 1.3.3 where the normal course of stakeholder engagement with *MDM/R service recipients* is not practicable, the *SME* may amend the *terms of service* or the *MDM/R manuals and procedures* by *urgent amendment* and shall provide *MDM/R service recipients* with the best information concerning the change as soon as possible.

2. Administration

2.1 Administration of the Terms of Service

2.1.1 The *SME* is responsible for the administration of the *terms of service* and the *MDM/R manuals and procedures.*

2.2 *SME* Compliance

2.2.1 The *SME* shall comply with, observe and perform any duties and obligations imposed on the *SME* by the *terms of service* and the *MDM/R manuals and procedures.*

2.3 Obligations of the *SME*

2.3.1 The *SME* shall provide access to the *MDM/R* for any *AMI* technology requested by *MDM/R service recipients*, provided that:

- the *AMI* technology is compliant with the *Functional Specification for an Advanced Metering Infrastructure*, (Ontario Regulation 425/06 – as amended by Ontario Regulation 440/07);
- the *AMI* technology is compliant with all other applicable laws and regulations governing its use in the province of Ontario;
- the *AMI* technology is compliant with all of the applicable functional and technical specifications required by the SME and has successfully completed such testing of the *AMI* as required by the *SME* to demonstrate such compliance;

- the cost for implementing new interfaces to new *AMI* technologies shall be borne by the *SME* and recovered through the *MDM/R Fee*; and

- the *SME* shall have authority over the implementation schedule for new *AMI* technologies and in the course of planning its implementation activities, shall consult with the *SME Steering Committee* to determine such matters as priority, scheduling and costing of such implementation, while the technical aspects of implementation shall be governed by the change management and release management processes described in sections 2.4 and 2.5 respectively.

2.3.2 The *SME* shall monitor the operational performance of the *MDM/R* to ensure that the service levels in Appendix 'A' are met by the *OSP* on a continual basis.

2.3.3 An *MDM/R service recipient* shall provide any information required by the *SME:*

- during the course of the *MDM/R* registration and enrollment process set out in section 3.3 to produce a forecast of future transactional volumes and shall communicate to the *SME* material changes to forecasts as soon as practical. The forecast is required to ensure that the hardware and systems used by the *OSP* to provide the *MDM/R* services will meet the forecasted volumes;

- at any time to produce a forecast of future transactional volumes for the purposes of assessing the impact of any proposed material change to the *smart metering initiative*. The *SME* shall consult with the *SME Steering Committee* prior to making any request under this provision; or

- at any time to produce a forecast of future transactional volumes for the purposes of assessing the impact of a material change in the circumstances of the *MDM/R service recipient*. The *SME* shall consult with the *SME Steering Committee* prior to making any request under this provision.

2.3.4 The *SME* shall ensure the continuity of *MDM/R* services provided under the *terms of service*. This may include the completion a formal procurement process upon the expiry of the contract with the *OSP*.

2.3.5 Subject to applicable law, the *SME* shall include *MDM/R service recipients* in the procurement process referred to in section 2.3.4 to the extent that such inclusion does not infringe upon the integrity of the procurement process itself. The *SME* shall have the right to make the final procurement decision.

2.3.6 The *SME* shall provide reasonable notice to an *MDM/R service recipient*, and its agents when required, should an event occur that may materially impact the

MDM/R service recipient's use of the *MDM/R*. These events, the resulting notification process, and reporting mechanism will be detailed in the *MDM/R manuals and procedures*.

2.4 Change Management

2.4.1 Subject to section 2.4.2, the *SME* shall establish and publish a change management process that will facilitate the evaluation of amendment proposals to the *terms of service*, the *MDM/R manuals and procedures,* the *MDM/R* or the specific configuration parameters for an *MDM/R service recipient*.

2.4.2 The transition to a new *OSP* or a new *MDM/R* may be subject to special release calendars and activities determined by the *SME*. The *SME* shall provide reasonable notice to all affected *MDM/R service recipients* prior to the commencement of any such transition activities.

2.4.3 The purpose of the change management process shall be to provide reasonable assurance that changes to the *terms of service,* the *MDM/R manuals and procedures*, the *MDM/R* or the specific configuration parameters of an *MDM/R service recipient* are identified, logged, communicated, assessed, prioritized, approved, designed and implemented in a controlled manner and in consultation with *MDM/R service recipients*.

2.4.4 For greater certainty, the change management process shall apply to any release of the *MDM/R* or the *MDM/R manuals and procedures* affecting:

- the functionality of the *MDM/R*;
- the delivery of an *MDM/R* service;
- the *MDM/R* technical interface design set out in section 4.2;
- any *MDM/R* standard falling under the provisions of section 4.3; or
- a target *MDM/R* service level falling under the provisions of Appendix 'A'.

2.5 MDM/R Change and Release Management

2.5.1 The *SME* shall establish and publish a change and release management process by which changes to the *MDM/R* will be implemented.

2.5.2 The purpose of the change and release management process shall be to provide reasonable assurance that changes to the *MDM/R* and are authorized, tested, and implemented in a controlled manner. The process shall include procedures for communicating, prioritizing and scheduling changes in consultation with *MDM/R service recipients.*

2.5.3 The *MDM/R* change and release management process shall be governed by a baseline calendar that communicates the steps and timelines regarding the lifecycle of each scheduled release of the *MDM/R*..

2.5.4 The *MDM/R* change and release management process shall allow for interim changes to the *MDM/R* outside of the baseline calendar.

2.6 MDM/R Configuration Change Management

2.6.1 The *SME* shall establish and publish an "MDM/R Configuration Change Management" process by which changes to *MDM/R* parameters or configuration settings that are configured for individual *MDM/R service recipients* are authorized and implemented.

2.6.2 The purpose of the "MDM/R Configuration Change Management" process shall be to provide reasonable assurance that changes to the *MDM/R* parameters or configurations that apply to individual *MDM/R service recipients* are authorized by *MDM/R service recipients* and implemented in a controlled manner. The process shall include procedures for scheduling and communicating implementation status of changes with affected *MDM/R service recipients.*

3. Preparation, Registration and Enrolment

3.1 Preparation and Registration

3.1.1 An *MDM/R service recipient* shall complete the preparation and registration process defined by the *SME* prior to utilizing the *MDM/R*. The *MDM/R service recipient* shall provide the *SME* with the information required by the *SME* for *MDM/R* administration and operation purposes.

3.2 Enrolment

3.2.1 An *MDM/R service recipient* shall complete an enrolment process defined by the *SME* prior to utilizing the *MDM/R*, which shall include the analysis, development and testing of the system and business process changes required for the *MDM/R service recipient* to integrate with the *MDM/R* and utilize the *MDM/R* services.

3.2.2 During the enrolment process, an *MDM/R service recipient* shall complete a self-certification assessment and provide a statement of readiness in the form specified by the *SME* at various stages of the preparation, registration and enrolment processes.

3.3 Status Reporting

3.3.1 The *SME* has the authority to require an *MDM/R service recipient* proceeding through the preparation, registration and enrolment process to provide status reports as required by the *SME.*

3.3.2 The *SME* may, at its discretion, delay the progression of an *MDM/R service recipient* through the preparation, registration and enrolment processes if that party fails to comply with the *SME*'s status reporting requirements.

4. Operation of the MDM/R

4.1 MDM/R Functional Design

4.1.1 Subject to applicable law, the *SME* shall establish and maintain operational services in accordance with the functional design of the *MDM/R* documented in the "Meter Data Management and Repository Detailed Design Document" as amended from time to time.

4.1.2 The *SME* shall make the "Meter Data Management and Repository Detailed Design Document" available to a local distribution company that is an *MDM/R service recipient* or its agent during the preparation, registration and enrollment process for MDM/R operation upon the execution by the *MDM/R service recipient* of a confidentiality agreement that is satisfactory to the *SME.*

4.2 MDM/R Technical Interface Design

4.2.1 The *SME* shall specify the interface to be used for the transfer of files between *the MDM/R service recipient* and the *MDM/R*. These interfaces will be required to support any *MDM/R* service as may be defined by the *SME* or applicable regulatory authority from time to time.

4.2.2 The *SME* shall document the technical interface design in the "Meter Data Management and Repository Technical Interface Specifications" and the "Meter Data Management and Repository Reports Technical Specifications". The *SME* shall *publish* these documents.

4.3 MDM/R Standards

4.3.1 The *SME* shall establish and publish standards, where required, regarding operational aspects of the *MDM/R*.

4.4 MDM/R Incident Management

4.4.1 The *SME* shall *publish* an "MDM/R Incident Management Framework" to identify, track, mitigate and address incidents involving the failure to provide an MDM/R service in the manner described in the applicable *MDM/R manuals and procedures*, or in accordance with the service levels outlined in Appendix 'A'. The "MDM/R Incident Management Framework" shall be detailed in the applicable *MDM/R manuals and procedures*, and include:

4.4.1.1 a means for *MDM/R service recipients* to notify the *SME* of any incidents regarding the provision of an MDM/R service;

4.4.1.2 a means for the *SME* to notify *MDM/R service recipients* of any incidents regarding the provision of an MDM/R service and any applicable interim steps being undertaken by the *SME* to mitigate such incidents;

4.4.1.3 where applicable, a means for the *SME* to communicate the status of incidents and known errors to *MDM/R service recipients* and any interim arrangements that should be observed by *MDM/R service recipients* until such time as a permanent solution to them is implemented;

4.4.1.4 a means for the *SME* to inform *MDM/R service recipients* of status updates of incidents including estimated time to resolution of incidents; and

4.4.1.5 a means for the *SME* to declare the resolution of problems and known errors to all affected *MDM/R service recipients* - including the implementation details involving the cutover from any interim arrangements that were put in place while the incident was in effect.

4.4.2 *MDM/R service recipients* shall make reasonable efforts to follow any direction from the *SME* to mitigate a known problem and to bring problems to the attention of the *SME* in a timely manner.

4.4.3 The *SME* shall establish and *publish* the procedures to manage operational incidents and problems encountered by organizations utilizing the services of the *MDM/R*.

4.4.4 The *SME* shall categorize reported incidents into different severity levels, and prioritize and respond to the incident based upon these categorizations. The *SME* shall publish the criteria used to categorize incidents.

4.4.5 The severity levels are as follows:

Severity	Characteristics
Severity 1 Incident	Severity 1 Incident means an incident that in the reasonable determination of *SME* results in one or more *MDM/R service recipients* not being able to receive: • a critical *MDM/R* service as defined in Appendix 'A' • a critical *MDM/R* service at the Service Level required for that measured service • a Service functioning in accordance with *MDM/R* specifications and the incident is having a severe impact on the business of *MDM/R service recipients*
Severity 2 Incident	Severity 2 Incident means an incident that in the reasonable determination of *SME*, results in the *MDM/R* not functioning to specifications and demonstrates itself as an intermittent problem with high impact on the business of *MDM/R service recipients*
Severity 3 Incident	Severity 3 Incident means in the reasonable determination of *SME*: • an incident causing non-critical degradation of performance • a non-critical *MDM/R* service as defined in Appendix 'A' not being available • an intermittent problem with low impact on the business of *MDM/R service recipients* • serious deficiencies in documentation

Severity	Characteristics
Severity 4 Incident	Severity 4 Incident means in the reasonable determination of *SME*: • a problem with the Services for which a long-term bypass is provided • a minor documentation or cosmetic problem

4.4.6 The *SME* shall not be responsible for incidents originating from a *MDM/R service recipient's* failure to comply with the technical interface specifications outlined in section 4.2.

4.4.7 Notwithstanding sections 4.4.1 to 4.4.4, the *MDM/R incident management framework* may designate a separate incident management processes for specific *MDM/R* services such that:

4.4.7.1 the *SME's* duties to gather and disseminate information relating to incidents involving those specific *MDM/R* services may be assigned to a third party; and

4.4.7.2 the designated third party handling incidents for those specific *MDM/R* services is legally bound to the *SME* to meet all applicable services levels for those specific *MDM/R* services as set out in Appendix 'A'.

4.5 MDM/R Service Levels

4.5.1 The *SME* will make best efforts to ensure that *MDM/R* operates in accordance with the applicable service levels for the benefit of all *MDM/R service recipients* prescribed in Appendix 'A', including:

4.5.1.1 work with the *OSP* to monitor service levels and address issues and incidents as they arise;

4.5.1.2 seek voluntary actions from *MDM/R service recipients* regarding the scheduling, frequency and volumetric restrictions of data flows to and from the MDM/R; and

4.5.1.3 impose limitations on the frequency and volume of data flows to and from the *MDM/R* where such restrictions are necessary to safeguard the integrity of the *MDM/R* and its associated service levels for the benefit of all *MDM/R service recipients* using the affected *MDM/R* services

4.5.2 Before imposing any limitations on the frequency and volume of data flows to and from the *MDM/R* under section 4.5.1.3, the *SME* shall consider the impact of the limitations on *MDM/R service recipients* that will be affected by those limitations.

4.5.3 Where the *SME* imposes limitations on the frequency and volume of data flows, it shall, at the first opportunity:

4.5.3.1 advise all affected MDM/R service recipients;

4.5.3.2 raise the matter with the *SME steering committee*;

4.5.3.3 propose to the *SME steering committee* remedies to such restrictions, including the potential cost and service implications for each proposed option; and

4.5.3.4 seek input from the *SME steering committee* as to whether or not the service restriction warrants the necessary costs to remedy the situation.

4.5.4 The *SME* shall report to *MDM/R service recipients*, the performance of each critical *MDM/R service* and each non-critical MDM/R service against the corresponding service level targets set out in Appendix 'A' on a schedule agreed to with the *SME Steering Committee*.

4.5.5 Notwithstanding section 4.5.4, the *SME* shall report to the *SME Steering Committee* all information relating to the reporting and distribution of Service Level Credits payable by the *OSP* to the *SME*.

4.6 MDM/R Business Continuity

4.6.1 The *SME* shall establish business continuity plans for the *SME* and ensure *OSP* establishes disaster recovery plans for the *MDM/R* for operating and recovering from an *MDM/R business interruption event* or an emergency situation requiring the *SME* to evacuate its principal control centre and move to a backup control centre.

4.6.2 The *SME* shall establish procedures for *SME, OSP, and MDM/R service recipients* coordination and communication in the event of an *MDM/R business interruption event* or an emergency situation requiring the *SME* to evacuate its principal control centre and move to a backup control centre. The *SME* shall *publish* those procedures in the "MDM/R Business Continuity Manual".

4.6.3 The procedures described in section 4.6.2 shall define the roles and responsibilities of the *SME*, *OSP* and *MDM/R service recipients* for responding to, recovering from and operating during an *MDM/R business interruption event* or emergency event.:

4.7 [intentionally left blank]

4.7.1 [Intentionally left blank]

4.7.2 [Intentionally left blank]

4.7.3 [Intentionally left blank]

4.7.4 [Intentionally left blank]

5. Settlement Invoicing and Payment Process

5.1 Settlement Procedure

5.1.1 The *SME shall* report the *smart metering charge* to *MDM/R service recipients* on the *IESO* physical market settlement statements in accordance with section 1.2, 6.1, 6.2, 6.3, 6.4, 6.5, 6.6., 6.7, 6.8 and 6.9 of Chapter 9 of the *market rules.*

5.1.2 An *MDM/R service recipient* may access its settlement statements in accordance with the above mentioned *market rules* and the applicable *SME* market manuals, including:

5.0 - Overview (MDP_MAN_0005);

5.1 - Settlement Schedule and Payments Calendars (SSPCs) (MDP_PRO_0031); and

5.5 - Physical Markets Settlement Statements (MDP_PRO_0033).

5.2 Invoicing Procedure

5.2.1 The *SME* shall invoice *MDM/R service recipients* for the *smart metering charge* on the *IESO* wholesale market invoices in accordance with sections 1.2, and 6.10 of Chapter 9 of the *market rules*.

5.2.2 An *MDM/R service recipient* may access its invoices in accordance with the above mentioned *market rules* and the applicable market manuals, including:

5.0 - Overview (MDP_MAN_0005);

5.1 - Settlement Schedule and Payments Calendars (SSPCs) (MDP_PRO_0031); and

5.6 - Physical Markets Settlement Invoicing (MDP_PRO_0035)

5.2.3 Charges for the *smart metering charge* will not be included in the prudential calculations for the distributor under the *market rules*.

5.3 Payment Procedure

5.3.1 *MDM/R service recipients* shall pay the *smart metering charge* reported on their wholesale market invoice issued by the *SME* in accordance with sections 1.2, and 6.11 of Chapter 9 of the *market rules*.

5.3.2 *MDM/R service recipients* shall fulfill their obligation to pay their invoices in accordance with the applicable *IESO* market manuals, including:

5.0 - Overview (MDP_MAN_0005);

5.1 - Settlement Schedule and Payments Calendars (SSPCs) (MDP_PRO_0031); and

5.9 - Settlement Payment Methods and Schedule (MDP_PRO_0036)

5.4 Payment Default

5.4.1 If the full amount due by an *MDM/R service recipient* has not been remitted by the *MDM/R service recipient* payment date, *default interest* shall accrue on all amount of the *smart metering charge* outstanding.

5.5 Allocation of Payment

5.5.1 If an *MDM/R service recipient* is also a participant in the wholesale market and the *MDM/R service recipient*:

- fails to remit the full invoice amount due by the *MDM/R service recipient* payment date; and
- does not direct the *SME* how to apportion the payment between the *smart metering charge* and all other settlement amounts on the invoice prior to the *IESO* payment date,

the *SME* shall allocate the payment made by the *MDM/R service recipient* first to satisfying any settlement amounts due under the *market rules* before being applied to the *smart metering charge.*

5.6 Settlement Disagreements and Disputes

5.6.1 An *MDM/R service recipient* may register a disagreement concerning the *smart metering charge* with the *SME* in accordance with section 6.6 of Chapter 9 of the *market rules.*

5.6.2 An *MDM/R service recipient* may, after having made reasonable efforts to resolve with the *SME* any disagreement, submit the matter to dispute resolution in accordance with section 6.8 of Chapter 9 of the *market rules.*

5.6.3 An *MDM/R service recipient* must commence any proceeding in respect of the calculation of the *smart metering charge* invoiced to it by the *SME* within the applicable limitation period set forth in section 2.5.1A.3 or 2.5.1A.4 of Chapter 3 of the *market rules.*

6. Supervision and Dispute Resolution

6.1 Supervision by the *SME*

6.1.1 { section deleted}

6.1.2 *The SME* may monitor and supervise the use of the *MDM/R* by an *MDM/R service recipient*, including:

- any aspect of usage of the *MDM/R*; and
- the form and content of information transferred between the *MDM/R* and the *MDM/R service recipient* and/or its designated agent(s).

6.1.3 The *SME* shall have the authority to monitor and supervise each *MDM/R service recipient*'s compliance with the procedures developed in support of the administration and operation of the *MDM/R*.

6.2 Remedies

6.2.1 If an MDM/R service recipient fails to comply with the *terms of service* and the *MDM/R manuals and procedures*, the *SME* may utilize any combination of following remedies:

- the issuance of warnings and notices and the subsequent publication of any such notices, including details of any associated disruption to any underlying *MDM/R* service caused by the actions of that *MDM/R service recipient*; and
- where necessary to safeguard the operational integrity of any *MDM/R* service, limit the *MDM/R service recipient's* access to one or more *MDM/R* services.

6.2.2 Nothing in the *terms of service* shall limit the *SME's* legal rights to further remedies for the breach of the *smart metering agreement* or the *terms of service* by any party.

7. Interpretation

7.1 Italicized Expressions

7.1.1 Italicized expressions used in the *terms of services* have the meanings ascribed thereto in the definitions set forth in section 7.8.

7.2 General

7.2.1 In the *terms of service*, unless the context otherwise requires:

- words importing the singular include the plural and vice versa;
- words importing a gender include any gender;
- when italicized, other parts of speech and grammatical forms of a word or phrase defined in the *terms of service* have a corresponding meaning;
- an expression importing a natural person includes any company, partnership, trust, joint venture, association, corporation or other private or public body corporate, any government agency or body politic or collegiate, and any other entity or body or class of entity or body designated by regulation made pursuant to the *Electricity Act, 1998* as coming within the definition of the word "person";
- a reference to a thing includes a part of that thing;
- a reference to a section, provision, condition, part or appendix is to a section, provision, condition, part or appendix of the *terms of service*;
- a reference to any statute, regulation, proclamation, order in council, ordinance, by-law, resolution, rule, order or directive includes all statutes, regulations, proclamations, orders in council, ordinances, by-laws or resolutions, rules, orders or directives varying, consolidating, re-enacting, extending or replacing it and a reference to a statute includes all regulations, proclamations, orders in council, rules and by-laws of a legislative nature issued under that statute;
- a reference to a document or provision of a document, including the *terms of service* or a provision of the *terms of service*, includes an amendment or supplement to, or replacement or novation of, that document or that provision of that document, as well as any exhibit, schedule, appendix or other annexure thereto;
- a reference to a person includes that person's executors, administrators, successors, substitutes (including, but not limited to, persons taking by novation) and permitted assigns;
- a reference to a body (including, without limitation, an institute, association or authority), whether statutory or not, which ceases to exist or whose functions are transferred to another body is a reference to the body which replaces it or which substantially succeeds to its powers or functions;

- a reference to sections of the *terms of service* separated by the word "to" (i.e., "sections 1.1 to 1.4") shall be a reference to the sections inclusively;
- a reference to a time:
    - without the qualification "EST" is a reference to eastern time, which is the prevailing eastern standard or eastern daylight time in the Province of Ontario;
    - followed by the qualification "EST" is a reference to eastern standard time in the Province of Ontario; and
    - without the qualification "am", "a.m.", "pm" or "p.m." is a reference to time based on a 24-hour clock; and
- a reference to a month, calendar month, year or calendar year shall mean the period that commences the first hour of the first trading day that starts in such month or year and terminates the last hour of the last trading day that commences in such month or year.

7.3 Headings

7.3.1 Headings in the *terms of service* are inserted for convenience of reference only and shall not affect the interpretation of the *terms of service*, nor shall they be construed as indicating that all of the provisions of the *terms of service* relating to any particular topic are to be found in any particular section, subsection, clause, provision, part or appendix.

7.4 Shall, Must and May

7.4.1 The words "shall" and "must" shall be construed as imperative and the word "may" shall be construed as permissive.

7.5 Explanatory Notes

7.5.1 Any provision in this document which is indicated as being an "explanatory note" or a "rule note" shall be deemed not to form a part of the *terms of service*. Such explanatory notes or rule notes are inserted for convenience only and shall not affect the interpretation of the *terms of service* nor be binding on the *SME* or on any *MDM/R service recipient*.

7.6 Computation of Time

7.6.1 In the computation of time under the *terms of service*, unless a contrary intention appears, if there is a reference to a number of days between two events, they are counted by excluding the day on which the first event happens and including the day on which the second event happens.

7.7 Currency

7.7.1 All references to a monetary amount are expressed in Canadian dollars in:

- the *terms of service*;
- *MDM/R manuals and procedures*
- a settlement statement; or
- an invoice.

7.7.2 Any payment required to be made by or to the *SME* or by or to an *MDM/R service recipient* shall be made in Canadian dollars.

7.8 Definitions

7.8.1 *AMI* has the meaning ascribed to it in the *smart metering agreement*.

7.8.2 *amendment proposal* means a proposal to amend the *terms of service* or an *MDM/R Manual or Procedure*.

7.8.3 *authorized agent* has the meaning ascribed to it in the *smart metering agreement.*

7.8.4 *CIS* means the customer information system used by an *MDM/R service recipient* for customer support and billing functions.

7.8.5 *default interest* means interest charged at the base lending rate that the bank where the *SME* settlement clearing account is maintained charges for commercial loans to its best and most creditworthy commercial customers plus 2%.

7.8.6 *IESO* means the Independent Electricity System Operator established and continued under Part II of the *Electricity Act, 1998.*

7.8.7 *market rules* means rules made under section 32 of the *Electricity Act, 1998.*

7.8.8 *MDM/R* means the Meter Data Management and Repository developed by the *SME* within which meter read data is processed to produce billing quantity data and such data is stored for future use.

7.8.9 *MDM/R business interruption event* means an event involving the substantial loss of the *OSP*'s primary *MDM/R* operations site availability that is expected to last longer than 24 hours.

7.8.10 *MDM/R fee,* means the *smart metering charge*, or any other allowable fee charged by the *SME* for the use of an *MDM/R* service that may be prescribed by applicable law.

7.8.11 *MDM/R manuals and procedures* means a series of documents specified by the *SME*, including the documents referred to in sections 4.1 4.2, 4.3 and 4.4, that describe procedures, standards and other requirements to be followed, met or performed by *MDM/R service recipients*, the *SME* and other persons in fulfilling their respective obligations under the terms of the *smart metering agreement* and the *terms of service*.

7.8.12 *MDM/R service recipient* means a party that has entered into a *smart metering agreement* with the *SME*.

7.8.13 *OEB* means the Ontario Energy Board or its successor.

7.8.14 *OPA* means the Ontario Power Authority or its successor.

7.8.15 *OSP* means the operational service provider engaged by the *SME* to assist with the development and operation of the *MDM/R*.

7.8.16 *publish* means, in respect of a document or information, to place that document or information on a website designated by the *SME*, and publication shall be interpreted accordingly.

7.8.17 *smart metering agreement* means an agreement, including the Schedules to such an agreement, between the *SME* and an *MDM/R service recipient*.

7.8.18 *smart metering charge* means any fee for the usage of an *MDM/R* service that may be prescribed by applicable law.

7.8.19 *smart metering initiative* means those policies of the Government of Ontario related to its decision to ensure Ontario electricity consumers are provided, over time, with smart meters.

7.8.20 *SME* means the *IESO* acting as the Smart Metering Entity designated under the *Electricity Act, 1998* (Ontario) to accomplish the Government of Ontario's *smart metering initiative* and any subsidiary of the *SME.*

7.8.21 *SME steering committee* means a consultative body constituted under the provisions of the *terms of service.*

7.8.22 *terms of service* means the terms and conditions governing the administration and operation of the *MDM/R* and any other infrastructure required to fulfill the objectives of the *smart metering initiative*, including the interfaces between the *MDM/R* and any external systems.

7.8.23 *urgent amendment* means an amendment to the *terms of service* or the *MDM/R manuals and procedures* on an urgent meeting one or more of the criteria set out in section 1.3.3.

Appendix 'A' – MDM/R Service Levels

Service Levels for Critical MDM/R Services:

Explanatory Note: The target service levels contained in this appendix for Critical *MDM/R* Services are commensurate with the target service level set out in an agreement between the *SME* and the *OSP*. In the event that the *OSP* fails to meet the target service levels for Critical *MDM/R* Services set out in this appendix, a service credit payable by the *OSP* to the *SME* may be triggered as per the contractual provisions in that agreement. Those service credits shall in turn be allocated to *MDM/R Service Recipients* as per the provisions of the *smart metering agreement* that is in force between the *MDM/R Service Recipient* and the *SME.* Please see the *smart metering agreement* for further details.

MDM/R Measured Service	**Measurement Method**	***SME* and *MDM/R Service Recipient* Obligations**	**Service Level Target (across all MDM/R service recipients per calendar month, unless otherwise indicated)**
Automatic Meter Read Processing	Meter Read Interface (all adaptors as indicated in *MDM/R v 1.0 Technical Interface Specification* document) - time to respond to a valid meter reads file received in accordance with the *MDM/R v 1.0 Technical Interface Specification* document	Meter read data received by the MDM/R received by 05:00 EST on the day immediately following each Daily Read Period - Exception Reports VE11, VE12, DC16, DC17, DC06, DC07, VE01, and VE02 shall be available by 07:10 EST on the day following the Daily Read Period - Meter Read data shall be available by 08:00 EST on the day following the Daily Read Period Meter read Data received by the MDM/R after 05:00 EST on the day immediately following each Daily Read Period - Meter read data will be processed within 6 hours from time of receipt of data by MDM/R - Exception Reports VE11, VE12, DC16, DC17, DC06, DC07, VE01, and VE02 will be available at the normally scheduled time on the second day immediately after the Daily Read Period Note: - Meter Read data file assumed to conform to all requirements of the *MDM/R v1.0 Technical Interface Specification* document	• Accumulated processing delay <= 240 minutes per calendar month, And • no more than one single delay > 45 minutes per calendar month

MDM/R Measured Service	**Measurement Method**	***SME* and *MDM/R Service Recipient* Obligations**	**Service Level Target (across all MDM/R service recipients per calendar month, unless otherwise indicated)**
Automatic Billing Quantity Processing	Billing Quantity Response – time to respond to a valid billing quantity request file received in accordance with the *MDM/R v 1.0 Technical Interface Specification* document	Billing Quantity Response File provided within 6 hours from receipt of the corresponding Billing Quantity Request File ('Pull' method) by the MDM/R for Billing Quantity Request Files received between 06:00 EST and 19:00 EST. - Billing Quantity Response File provided by 21:05 EST on Day N+2 for billing quantity Requests initiated via the scheduled 'Push' method Note: - Billing Quantity Request File assumed to conform to all requirements of the MDM/R Technical Interface Specification. - Billing Quantity Data must have successfully completed the VEE process no later than the time stamp of each Billing Quantity Request ("Pull" method) or by 15:00 EST on Day N+2 ("Push" method)	• Accumulated processing delay <= 240 minutes per calendar month, And • no more than one single delay > 45 minutes per calendar month
Automatic MDM/R Master Directory (MMD) incremental synchronization Processing	Processing of Incremental Synchronization files (version 00 or higher as adaptors as indicated in *MDM/R v 1.0 Technical Interface Specification* document) – response time to apply valid incremental synchronization files to the MMD	For all Incremental Synchronization files received by 16:00 EST on Daily Read Period 'N': - MMD Changes applied by 00:00 EST on daily read period 'N + 1' following the day in which the Incremental Synchronization file was received (i.e. by the beginning of the day immediately following daily read period 'N') - The maximum number of daily updates via incremental synchronization that are subject to this target service level is limited to the higher of 5000 or 0.50% of the registered service delivery points for the *MDM/R service recipient.*	>99.8% percent Automatic MMD Processing Completion across all *MDM/R service recipients* per Daily Read Period
MDM/R Graphical User Interface (GUI)	GUI availability rate	Available in the highest availability window (06:00 to 20:00) each calendar day Outside of the highest availability window, this interface may occasionally be subject to discretionary maintenance outages by the OSP, of which *MDM/R service recipients* will receive reasonable notice from the *SME.*	>99.8% availability across all MDM/R service recipients per calendar month

Service Level Targets for Non-Critical MDM/R Services:

Explanatory Note: The target service levels contained in this appendix for non-critical *MDM/R* services are commensurate with the target service level set out in an agreement between the *SME* and the *OSP* or any other service provider providing the services listed below under contract with the *SME*. The non-critical MDM/R service level targets listed below do not trigger a service credit or subsequent payments that fall under the provisions of the *smart metering agreement*.

MDM/R Measured Service	**Measurement Method**	***SME* Obligations**	**Service Level Target (across all MDM/R service recipients per calendar month, unless otherwise indicated)**
Public Interactive Voice Response (IVR) system	Public IVR availability rate	Public IVR to operate on a 24-hour basis, 7 days per week.	>99.0% availability across all *MDM/R service recipients* per calendar month
Help Desk	Help Desk hours of availability and response time	Help Desk available to respond to incidents on a 24-hour basis, 7 days per week.	24 hour availability for all *MDM/R service recipients* – 7 days per week Response time for incidents: Severity 1:30 minutes (7x24 Mon –Sun, including holidays) Severity 2: 3 hours (06:00 – 23:00 EDT Mon –Sun, including holidays)
MDM/R Web Services Interface	To be determined	To be determined.	